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Issues in Midterm Analysis and Forecasting 1999

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Preface

Issues in Midterm Analysis and Forecasting 1999 (*Issues*) presents a series of eight papers, which cover topics in analysis and modeling that underlie the *Annual Energy Outlook 1999* (*AEO99*), as well as other significant issues in midterm energy markets. *AEO99*, DOE/EIA-0383(99), published in December 1998, presents national forecasts of energy production, demand, imports, and prices through the year 2020 for five cases—a reference case and four additional cases that assume higher and lower economic growth and higher and lower world oil prices than in the reference case. The forecasts were generated using the Energy Information Administration's (EIA) National Energy Modeling System (NEMS).

The papers included in *Issues* describe underlying analyses for the projections in *AEO99* and the forthcoming *Annual Energy Outlook 2000* and other analytical products of EIA's Office of Integrated Analysis and Forecasting. Their purpose is to provide public access to analytical work done in preparation for the midterm projections and to other unpublished analyses. Specific topics were chosen for their relevance to current energy issues or to highlight modeling activities in NEMS.

The *AEO99* projections are used by Federal, State, and local governments, trade associations, and other planners and decisionmakers in the public and private sectors. They are published in accordance with Section 205(c) of the Department of Energy Organization Act of 1977 (Public Law 95-91), which requires the Administrator of EIA to prepare an annual report that contains trends and projections of energy consumption and supply.

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Issues will be available on the EIA Home Page on the Internet (*http://www.eia.doe.gov*) by mid-August 1999 and on the next release of the EIA CD-ROM after August. *AEO99*, the assumptions underlying the *AEO99* projections, and tables of regional and other detailed results from the *AEO99* forecasts are also available on the CD-ROM and on the EIA Home Page. *The National Energy Modeling System: An Overview*, DOE/EIA-0581(98), which provides a summary description of NEMS, and complete model documentation reports for NEMS are available on the CD-ROM and on the EIA Home Page.

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Contents

Contents (Continued)

Tables

Tables (Continued)

Figures

Trends in Power Plant Operating Costs

Sectoral Pricing in a Restructured Electricity Market

Modeling the Costs of U.S. Wind Supply

Figures (Continued)

Page

Trends in Power Plant Operating Costs

by
J. Alan Beamon and Thomas J. Leckey

As competitive pressures grow in the electricity generation sector, power plant operators are expected to be under increasing pressure to reduce their operating costs. Pressure will come from efforts to increase profits and to protect current market share from new suppliers. This article examines changes in fossil steam power plant operating costs over the period 1981 through 1997. While it is difficult to determine the degree to which growing competitive pressures rather than technological changes influenced the falling costs, the changes will be critical in determining the competitiveness of existing units in the future. Key issues that are examined are the extent to which fossil steam power plant operating costs have declined in recent years and prospects for further cost reductions.

Background

Over the past two decades, U.S. electricity markets have undergone significant change. Historically, for most customers, all the services involved in producing electricity and delivering it to them have been provided by one company. For the most part, that company determined how much generating capacity was needed, designed and built the production facilities (generating plants), designed and built the delivery systems (transmission and distribution lines), and billed the customers for those services. This situation is changing, especially in the generation sector.

Where it was once the exclusive domain of integrated power companies,[1] there are now many other players emerging in the generation sector. Much of this change has been spurred by legislative and regulatory changes, including the Public Utility Regulatory Policies Act of 1978 (PURPA), the Energy Policy Act of 1992 (EPACT), and the Federal Energy Regulatory Commission (FERC) Orders 888 and 889 in 1996. PURPA, coming in the midst of the energy crises of the 1970s, was implemented to encourage energy efficiency and investment in domestic energy resources. It required that utilities purchase power from qualifying facilities—mainly, small facilities using renewable fuels or burning fossil fuels to produce both electricity and useful thermal energy (heat or steam). While there have been problems with the implementation of PURPA, particularly with the calculation of the appropriate price to pay for power from these facilities, it has succeeded in bringing new players into the generation market.

The role of nonutility generators was further stimulated by EPACT. Before its passage, nonutility companies wishing to own and operate power plants were open to regulation as utilities under the Public Utility Holding Company Act of 1935 (PUHCA) and could be required to file extensive information about their company operating costs and performance. This requirement to essentially open their books for examination by regulators, even for those parts of the company not associated with power generation, limited the willingness of nonutility companies to enter into the electricity generating business. To eliminate this problem, EPACT created a new class of generators, referred to as exempt wholesale generators (EWGs), which could be owned and operated by nonutilities or by utilities outside their own service territories and could sell power freely on the wholesale market. EWGs are not subject to the stringent information requirements of PUHCA.

The willingness of nonutility companies to enter into the electricity generating business was also limited because of the difficulty of arranging delivery from a new plant to potential customers. Most of the power lines that deliver electricity to customers are owned and operated by the companies that sell the electricity. Those companies have built the lines to meet the needs of their customers, and they have been reluctant to allow others the use of their lines to ship power. Recognizing that all power producers need access to transmission wires—the means for delivering their product—the FERC issued Orders 888 and 889 to create a more competitive generation market. The FERC orders required that transmission system owners post standard rates for use of

[1]Integrated power companies are electric utilities that own and operate the generation, transmission and distribution facilities needed to meet the requirements of their franchised customers.

their lines and make unused capacity available to customers other than their own.

The net result of these changes is the emergence of a vibrant market for new generating facilities. When new capacity is needed, project proposals can be expected from a wide variety of sources. In fact, some plants, so-called "merchant plants," are being built to compete directly with existing plants rather than to meet growing demand. The emergence of these new players means that operators of existing plants must continually look for ways to reduce their costs to remain competitive. While it is impossible to tell to what degree regulatory changes have contributed to changing power plant operational costs to date, the pressure for continued improvements is not expected to lessen.[2]

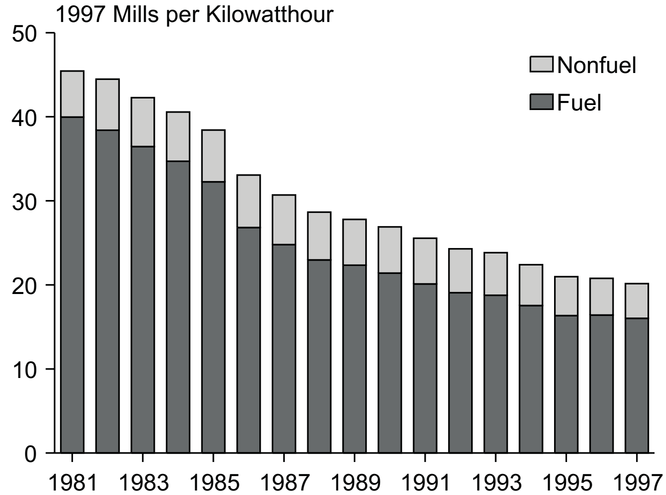
Data Sources

The data used in this analysis were compiled by the Utility Data Institute (UDI) from information reported on the FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others," and Form EIA-412, "Annual Report of Public Electric Utilities." The Form 1 is an annual survey that gathers financial data from investor-owned utilities for formal investigation of electric rates, rate levels, and financial audits. Specific data collected include electric operating revenues, electric maintenance expenses, and generating plant statistics. Most of the data used in this analysis come from Schedule X, "Electric Plant Statistical Data," which is reported for all steam plants 25 megawatts or larger and for gas turbine or internal combustion plants 10 megawatts or larger. Each year there are approximately 193 respondents to the Form 1. Form EIA-412 collects similar data from approximately 500 municipal and public utilities each year. This analysis examines fossil steam plant operations and maintenance (O&M) costs over the 1981 through 1997 period.[3]

Operating Cost Trends

Between 1981 and 1997, fossil steam plant operating costs have fallen significantly (Figure 1). Total fossil steam plant O&M costs per kilowatthour of electricity produced have fallen by 56 percent in real terms. In fact, nominal O&M costs have remained nearly flat over the period, and fuel costs have declined by nearly 9 percent in nominal terms.[4] The vast majority of this reduction has come from declining fuel costs, which have fallen by 60 percent on a per-kilowatthour basis.

Figure 1. Fossil Steam Plant Operations and Maintenance Costs, 1981-1997



Sources: FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others," and Form EIA-412, "Annual Report of Public Electric Utilities" (1981-1997).

Some of the decline clearly reflects the return of energy markets to historic levels after the fuel price increases of the mid- and late 1970s; between 1970 and 1980, coal and natural gas prices to electric utilities rose by 204 and 783 percent, respectively. By 1990, however, coal prices in real terms had returned to pre-embargo levels, and in 1996 they reached a new historic low, from which they have continued to decline.[5] Nonfuel O&M costs have also fallen sharply, declining by 25 percent over the period (Table 1 and Figure 1). Among the fuels, the total decline has been almost the same: 49 percent for coal plants and 52 percent for oil and gas plants.[6] The overall decline was sharper than those for the individual fuels because the share of fossil steam generation accounted for by relatively low-cost coal plants increased from 72 to 87 percent.

Coal Steam Plants

Where once they produced power at an average of over 3.5 cents per kilowatthour, total production costs for coal-fired plants now average less than 1.8 cents per kilowatthour (Figure 2 and Table 2). Declining fuel costs

[2]For further discussion of the changing industry structure, see *The Changing Structure of the Electric Power Industry: Selected Issues 1998*, DOE / EIA-0562(98) (Washington, DC, July 1998).

[3]Regulated utilities report their costs in response to both Federal and State regulation. This analysis acknowledges the inherent difficulty of ascribing strict technical meaning to costs reported as "operating," especially the distinction, if any, between fixed and variable costs. Also, the content and character of reported costs may have changed in the past several years as competitive issues have become more pronounced.

[4]Unless otherwise stated, all the monetary values and calculations presented in this report are given in real 1997 dollars.

[5]Energy Information Administration, *Annual Energy Review 1998*, DOE / EIA-0384(98) (Washington, DC, July 1999), Table 7.8.

[6]Because many oil and gas steam plants can switch back and forth between fuels, they are aggregated in this analysis.

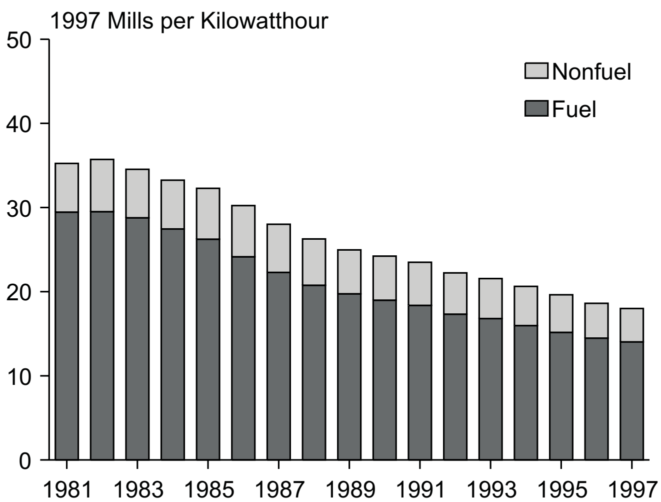
Table 1. Fossil Steam Plant Operations and Maintenance Costs, 1981-1997

Year	Capacity (Megawatts)	Generation (Thousand Kilowatthours)	Fuel (1997 Dollars)	Total Nonfuel (1997 Dollars)	Fuel (Mills per Kilowatthour)	Nonfuel (Mills per Kilowatthour)	Total Production (Mills per Kilowatthour)
1981	385,929	1,575,674,225	62,975,524,370	8,630,113,999	39.97	5.48	45.44
1982	412,938	1,555,652,910	59,745,257,414	9,442,540,715	38.41	6.07	44.48
1983	424,230	1,619,872,921	59,048,520,113	9,427,733,649	36.45	5.82	42.27
1984	435,888	1,697,846,310	58,923,996,040	9,952,591,520	34.71	5.86	40.57
1985	453,477	1,756,950,576	56,676,427,149	10,828,858,046	32.26	6.16	38.42
1986	456,651	1,743,567,437	46,772,159,501	10,885,713,440	26.83	6.24	33.07
1987	461,408	1,812,650,361	44,939,763,615	10,704,403,807	24.79	5.91	30.70
1988	462,893	1,906,901,849	43,792,779,635	10,847,790,833	22.97	5.69	28.65
1989	466,169	1,934,621,433	43,226,040,887	10,537,230,489	22.34	5.45	27.79
1990	469,255	1,921,672,263	41,136,540,826	10,560,409,433	21.41	5.50	26.90
1991	472,534	1,909,148,545	38,403,461,613	10,371,046,045	20.12	5.43	25.55
1992	472,655	1,912,634,257	36,474,519,112	9,987,287,062	19.07	5.22	24.29
1993	469,528	1,953,792,504	36,666,102,978	9,902,692,491	18.77	5.07	23.84
1994	466,710	1,964,967,375	34,470,527,774	9,555,774,162	17.54	4.86	22.41
1995	464,289	1,963,740,860	32,096,070,053	9,101,325,045	16.34	4.63	20.98
1996	465,097	2,014,510,149	33,066,835,339	8,790,566,243	16.41	4.36	20.78
1997	465,626	2,071,399,409	33,191,910,572	8,551,685,295	16.02	4.13	20.15

Sources: FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others," and Form EIA-412, "Annual Report of Public Electric Utilities" (1981-1997).

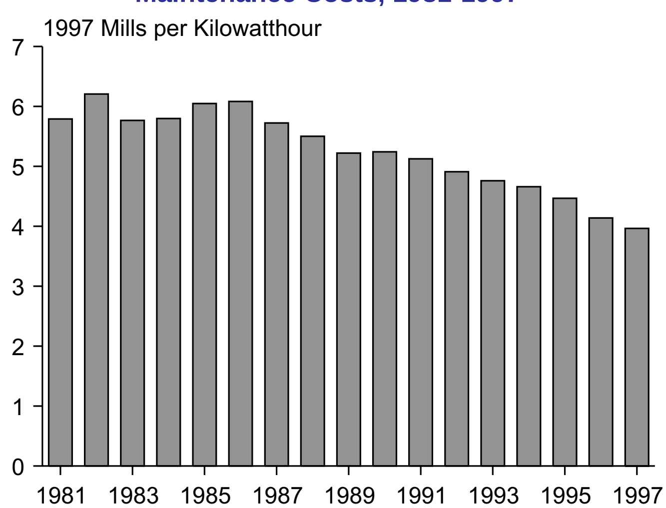
have again been the main factor in the decline. During the period, minemouth coal prices declined by 60 percent, from $45 per short ton ($2.12 per million Btu) in 1981 to $18 per short ton ($0.88 per million Btu) in 1997.[7] The decline reflects a shift from eastern subsurface mines to western surface mines, as well as a rapid increase in mining productivity in all types of mines.[8] Over the same period, the delivered price of coal to electricity power plants fell from $2.61 to $1.27 per million Btu. Other factors, including increased utilization, reductions in nonfuel expenditures, and fewer employees per plant, have also played a role (Figure 3).

Figure 2. Coal Plant Production Costs, 1981-1997



Sources: FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others," and Form EIA-412, "Annual Report of Public Electric Utilities" (1981-1997).

Figure 3. Coal Steam Plant Nonfuel Operations and Maintenance Costs, 1981-1997



Sources: FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others," and Form EIA-412, "Annual Report of Public Electric Utilities" (1981-1997).

[7]Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998), Tables 7.8 and A5.

[8]For more information on changes in the coal industry, see Energy Information Administration, *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, December 1998), and *Longwall Mining*, DOE/EIA-TR-0588 (Washington, DC, March 1995).

Table 2. Coal Steam Plant Operations and Maintenance Costs, 1981-1997

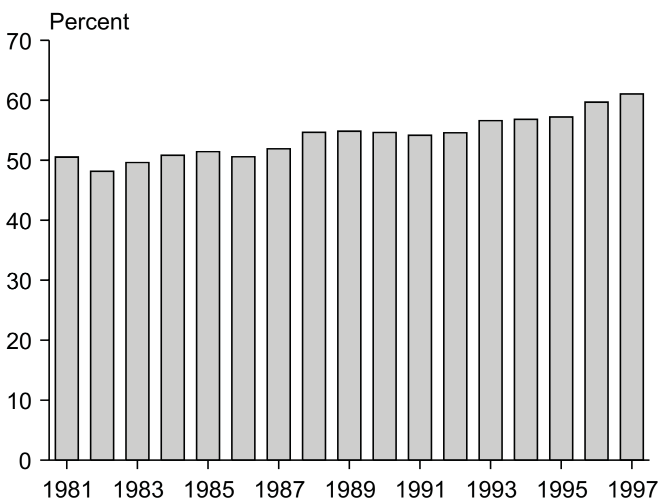
Year	Capacity (Megawatts)	Generation (Thousand Kilowatthours)	Fuel (1997 Dollars)	Total Nonfuel (1997 Dollars)	Fuel (Mills per Kilowatthour)	Nonfuel (Mills per Kilowatthour)	Total Production (Mills per Kilowatthour)
1981	259,539	1,148,992,891	33,842,032,705	6,653,450,298	29.45	5.79	35.24
1982	279,252	1,177,928,612	34,763,820,670	7,310,528,614	29.51	6.21	35.72
1983	292,796	1,272,573,389	36,615,713,670	7,337,676,799	28.77	5.77	34.54
1984	303,203	1,349,972,538	37,050,562,081	7,826,879,765	27.45	5.80	33.24
1985	315,456	1,421,380,003	37,280,096,310	8,596,781,832	26.23	6.05	32.28
1986	317,916	1,408,730,570	34,014,571,141	8,568,806,351	24.15	6.08	30.23
1987	324,694	1,476,798,132	32,918,684,732	8,451,851,094	22.29	5.72	28.01
1988	325,516	1,558,553,591	32,348,821,393	8,574,467,352	20.76	5.50	26.26
1989	327,777	1,574,384,025	31,072,630,168	8,220,513,022	19.74	5.22	24.96
1990	334,613	1,601,190,743	30,391,971,139	8,393,532,980	18.98	5.24	24.22
1991	336,296	1,595,449,175	29,306,061,530	8,177,760,879	18.37	5.13	23.49
1992	337,707	1,614,687,420	27,969,606,515	7,927,935,592	17.32	4.91	22.23
1993	335,096	1,661,706,887	27,916,019,989	7,908,647,569	16.80	4.76	21.56
1994	333,324	1,658,841,157	26,484,494,462	7,729,068,061	15.97	4.66	20.62
1995	335,856	1,683,198,487	25,510,935,050	7,518,131,822	15.16	4.47	19.62
1996	337,313	1,763,599,356	25,529,172,316	7,299,049,043	14.48	4.14	18.61
1997	338,005	1,807,668,491	25,359,900,563	7,165,038,725	14.03	3.96	17.99

Sources: FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others," and Form EIA-412, "Annual Report of Public Electric Utilities" (1981-1997).

The per-kilowatthour production costs of coal plants were also driven down by their increased utilization. Many of the nonfuel costs associated with the operation of a large steam plant are unaffected by the utilization of the facility. For example, it takes little additional staff to run the plant whether it is operating at half or full load. As a result, as the utilization of a plant rises its average unit operating costs fall. The average capacity factor of coal plants over the 1981 to 1997 period increased from 51 percent to 61 percent (Figure 4), contributing to the improvement in per-kilowatthour O&M costs.

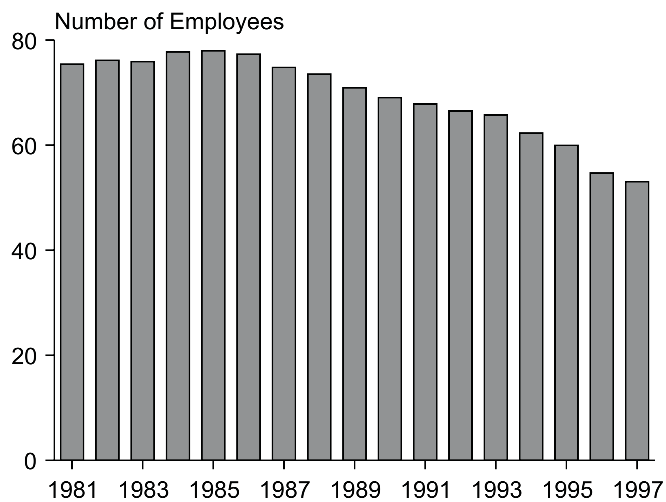
The decline in nonfuel O&M costs was due in part to reductions in employment at coal plants (Figure 5). In 1981 an average 300-megawatt coal plant—roughly large enough to meet the power needs of 170,000 homes—had 75 employees. The number increased slightly to 78 in 1985, but since then it has fallen sharply.

Figure 4. Coal Steam Plant Capacity Factors, 1981-1997



Sources: FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others," and Form EIA-412, "Annual Report of Public Electric Utilities" (1981-1997).

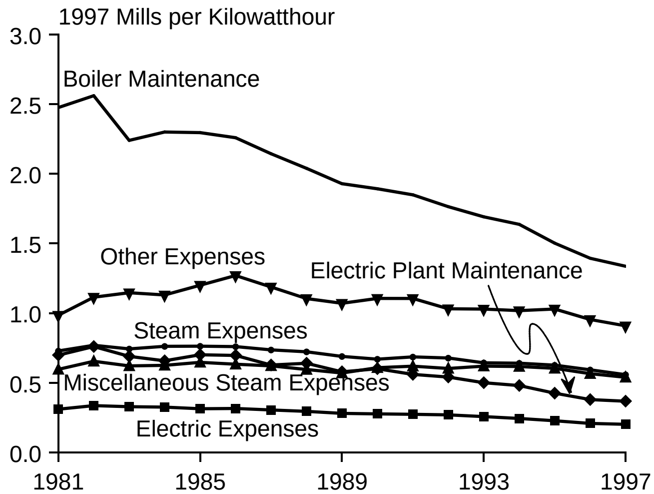
Figure 5. Coal Steam Plant Employees (Average for a 300-Megawatt Plant), 1981-1997



Sources: FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others," and Form EIA-412, "Annual Report of Public Electric Utilities" (1981-1997).

By 1997 the average had fallen to 53, a decline of 32 percent. Considering that the generation from coal plants increased by 27 percent between 1985 and 1997, the drop in employment per megawatt of plant capacity is even more impressive. In addition, the reduction in employees—and in nonfuel O&M costs in general—did not begin in earnest until 1986-1987, while fuel costs have been dropping over the entire 1981 to 1997 period.

Figure 6. Coal Steam Plant Nonfuel Production Expenses, 1981-1997



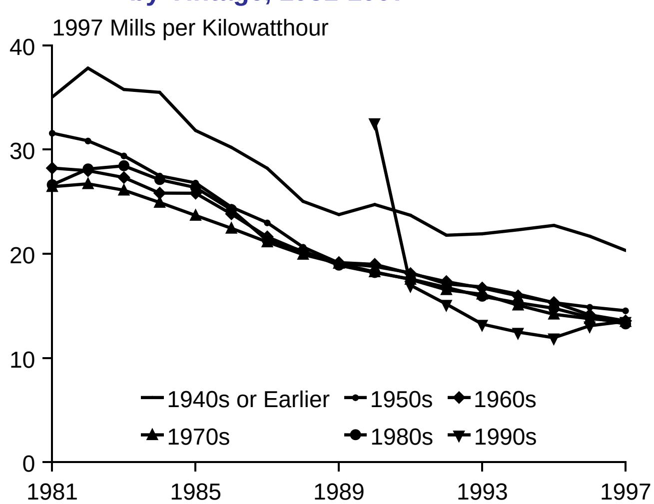
Sources: FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others," and Form EIA-412, "Annual Report of Public Electric Utilities" (1981-1997).

Among the specific cost items reported on the Form 1, the greatest reduction, over 46 percent, was for maintenance on the boiler (Figure 6).[9] As mentioned previously, a portion of this reduction in per-kilowatthour terms occurred simply because of the increase in utilization of coal plants. Maintenance on the electric plant also declined significantly, by over 46 percent. It is possible that some of the reductions reflect utility efforts to defer maintenance and save money in preparation for competition; however, it is unlikely that this could have been occurring since 1986 while still maintaining plant performance.

All vintages of coal plants have shown improvements in fuel and nonfuel O&M costs.[10] In terms of fuel costs per kilowatthour, only plants built in the 1940s or earlier are significantly different from the average units (Figures 7 and 8). This difference reflects the relative inefficiency of the older plants. Since the 1950s, however, coal plant efficiencies have changed very little. The smaller plants built in the 1940s and earlier have average heat rates near 13,000 (26 percent efficiency), while those built since the 1950s have average heat rates near 10,000 (34 percent efficiency).

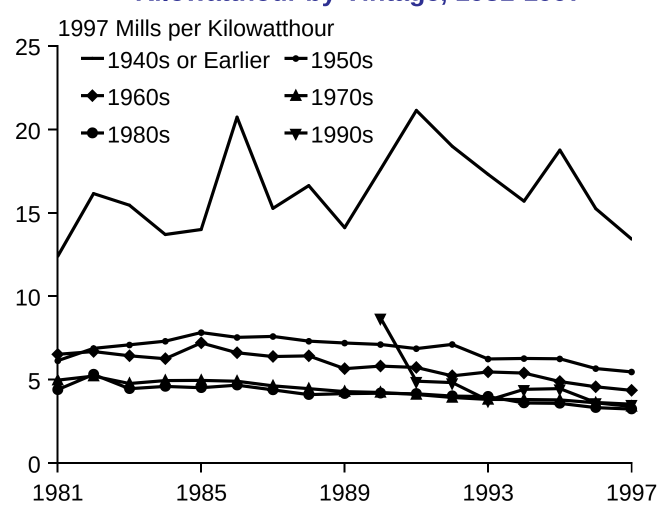
In terms of plant size, all have benefitted from the dramatic fall in coal prices (Figure 9). The smaller plants have slightly higher per-kilowatthour fuel costs, again reflecting the fact that many of them are also quite old and less efficient than other plants. For nonfuel O&M costs there is significant divergence among plants of

Figure 7. Coal Plant Fuel Costs per Kilowatthour by Vintage, 1981-1997



Sources: FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others," and Form EIA-412, "Annual Report of Public Electric Utilities" (1981-1997).

Figure 8. Coal Plant Nonfuel Costs per Kilowatthour by Vintage, 1981-1997

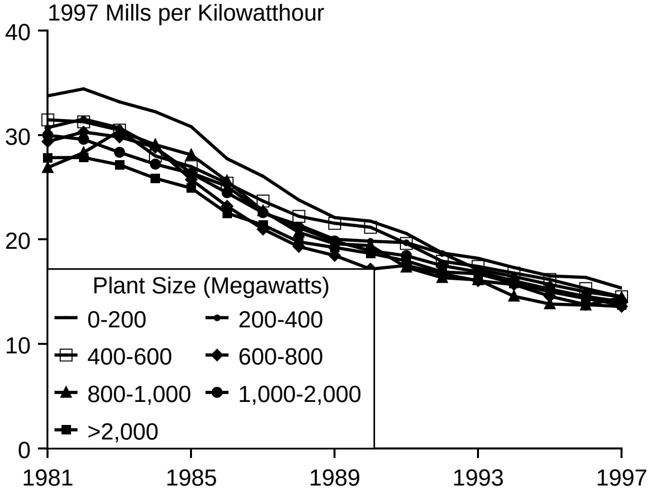


Sources: FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others," and Form EIA-412, "Annual Report of Public Electric Utilities" (1981-1997).

[9]Twelve specific cost categories are reported for plant operations on FERC Form 1. In Figure 6, the top five are shown individually, and the remainder are grouped in the "Other Expenses" category.

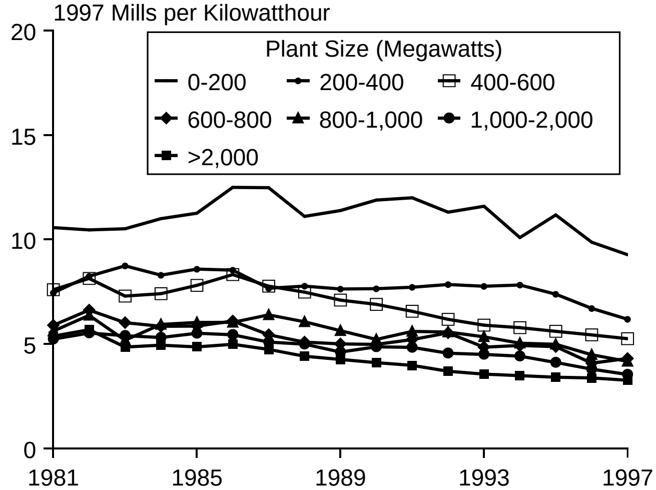
[10]The data provided on FERC Form 1 are reported at the plant level. In some cases, plants consist of units that were built many years apart. To calculate the vintages used in this section, the operation start dates of the first and last units added at a plant were averaged. If they differed by more than 10 years, the plant was excluded. A total of 229 gigawatts or 68 percent of coal-fired capacity was included in the calculations by vintage.

Figure 9. Coal Plant Fuel Production Costs by Plant Size, 1981-1997



Sources: FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others," and Form EIA-412, "Annual Report of Public Electric Utilities" (1981-1997).

Figure 10. Coal Plant Nonfuel Production Costs by Plant Size, 1981-1997



Sources: FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others," and Form EIA-412, "Annual Report of Public Electric Utilities" (1981-1997).

different sizes (Figure 10). Though all plants sizes have shown improvement, smaller plants still have significantly higher nonfuel O&M costs than do larger plants. Nonfuel O&M costs for plants 200 megawatts and smaller are nearly 3 times those for plants 2,000 megawatts and larger.

Oil and Gas Steam Plants

Like their coal steam counterparts, oil and gas steam plants also saw rapidly declining production costs over the 1981 to 1997 time period.[11] From 7.2 cents per kilowatthour in 1981, average production costs for these plants fell to 2.9 cents per kilowatthour by 1995, a 60-percent reduction, before rising to 3.5 cents per kilowatthour in 1997 (Table 3 and Figure 11). Even with the sharp increase in fuel prices in 1996 that drove their production costs up, the overall decline between 1981 and 1997 was 51 percent.

Fuel price reductions have been key in this trend, declining by 57 percent in per-kilowatthour terms over the period. Most of the reduction occurred between 1985 and 1986, when the average price of natural gas sold to electric utilities fell from $5.05 to $3.37 per thousand cubic feet, a 33-percent drop. As with the coal steam plants, nonfuel O&M costs also fell, though at a different rate and pattern over the years. Nonfuel costs per kilowatthour increased over the first half of the period, between 1981 and 1991, before beginning a steady decline from 0.70 to 0.52 cents per kilowatthour in 1997, a 25-percent reduction. As with coal steam plants, the decline in nonfuel O&M costs at oil and gas steam plants appeared in the later half of the 1980s. In contrast to coal plants, the decline in nonfuel O&M costs at oil and gas steam plants since 1991 occurred even though the output of the plants fell. The utilization of oil and gas steam plants declined from an average rate of 39 percent in 1981 to 24 percent in 1997. Thus, the nonfuel cost reductions per kilowatthour reflect significant operational efficiency improvements rather than the impact of increased utilization.

The retirement of older, inefficient oil and gas steam plants has played only a small role in the decline of their average nonfuel operating costs. The group of oil and gas steam plants studied here remained largely intact over the period 1981 to 1997, suggesting that performance improvements represent more than the attrition of poor performers and the survival of efficient plants. In fact, 169 of the plants, comprising 111 gigawatts (about 87 percent of total oil and gas capacity), operated throughout the 1981 through 1997 period. Not surprisingly, the units that have retired were among the oldest; however, a relatively small number, only 5.7 gigawatts, were retired during the years 1990-1996 (Table 4).[12]

The observed production cost improvement for oil and gas steam plants completely changed the economics of the facilities. In 1981, only 4.5 percent of total capacity was able to operate at costs below 2 cents per kilowatthour; 51 percent of the capacity, producing nearly 58 percent of the generation, operated at costs in excess of 7 cents per kilowatthour (Figure 12). By 1997, the production cost distribution had changed, with 78 percent of the capacity operating at costs less than 4

[11] A total of 332 plants for which the primary fuel was reported as either oil or natural gas were included in this analysis. A few of these plants also burned coal as a secondary fuel, especially in the early 1980s.

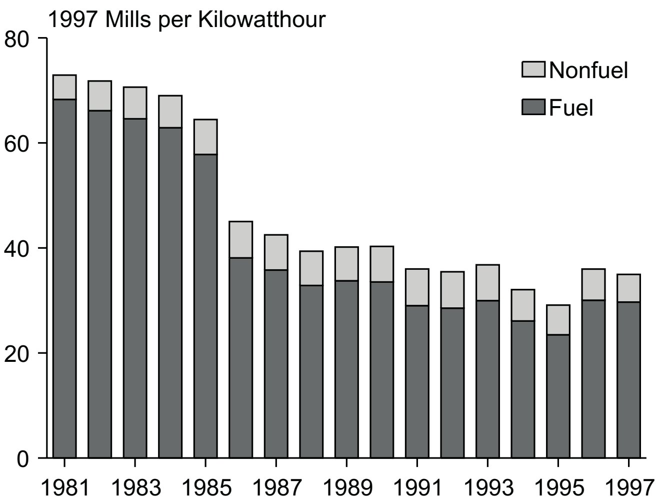
[12] Preliminary data from Form EIA-860 indicate that about 612 megawatts of oil and gas steam capacity were retired in 1997.

Table 3. Oil and Gas Steam Plant Operations and Maintenance Costs, 1981-1997

Year	Capacity (Megawatts)	Generation (Thousand Kilowatthours)	Fuel (1997 Dollars)	Total Nonfuel (1997 Dollars)	Fuel (Mills per Kilowatthour)	Nonfuel (Mills per Kilowatthour)	Total Production (Mills per Kilowatthour)
1981	126,390	426,681,334	29,133,491,665	1,976,663,701	68.28	4.63	72.91
1982	133,686	377,724,298	24,981,436,743	2,132,012,101	66.14	5.64	71.78
1983	131,434	347,299,532	22,432,806,443	2,090,056,850	64.59	6.02	70.61
1984	132,685	347,873,772	21,873,433,959	2,125,711,755	62.88	6.11	68.99
1985	138,020	335,570,573	19,396,330,838	2,232,076,214	57.80	6.65	64.45
1986	138,735	334,836,867	12,757,588,360	2,316,907,090	38.10	6.92	45.02
1987	136,714	335,852,229	12,021,078,883	2,252,552,712	35.79	6.71	42.50
1988	137,377	348,348,258	11,443,958,242	2,273,323,480	32.85	6.53	39.38
1989	138,392	360,237,408	12,153,410,719	2,316,717,467	33.74	6.43	40.17
1990	134,642	320,481,520	10,744,569,687	2,166,876,453	33.53	6.76	40.29
1991	136,239	313,699,370	9,097,400,084	2,193,285,166	29.00	6.99	35.99
1992	134,948	297,946,837	8,504,912,597	2,059,351,470	28.55	6.91	35.46
1993	134,432	292,085,617	8,750,082,989	1,994,044,922	29.96	6.83	36.78
1994	133,386	306,126,218	7,986,033,312	1,826,706,101	26.09	5.97	32.05
1995	128,433	280,542,373	6,585,135,003	1,583,193,223	23.47	5.64	29.12
1996	127,784	250,910,793	7,537,663,023	1,491,517,200	30.04	5.94	35.99
1997	127,622	263,730,918	7,832,010,009	1,386,646,570	29.70	5.26	34.95

Sources: FERC Form 1, “Annual Report of Major Electric Utilities, Licensees and Others,” and Form EIA-412, “Annual Report of Public Electric Utilities” (1981-1997).

Figure 11. Oil and Gas Steam Plant Operations and Maintenance Costs, 1981-1997



Sources: FERC Form 1, “Annual Report of Major Electric Utilities, Licensees and Others,” and Form EIA-412, “Annual Report of Public Electric Utilities” (1981-1997).

cents and 43 percent operating below 3 cents per kilowatthour (Figure 13). Because of their relatively high costs, few oil and gas steam plants were added in the 1980s. However, the introduction of new gas technologies—particularly the very efficient natural-gas-fired combined-cycle plant—over the next decade or so is expected to contribute to a further reduction in natural gas plant operating costs.

Examining these plants by vintage shows that the newer plants, about 56 percent of the oil and gas steam capacity and mostly built in the 1970s, generally have the best performance. As would be expected, the oldest plants, those in operation during the 1950s or before (about 9 gigawatts), had both higher fuel costs and significantly higher nonfuel O&M costs.[13] However, plants beginning operation any time after 1960 show similar nonfuel O&M costs, with less than a 0.1-cent difference among the vintages by 1997 (Figure 14). (The unusually poor performance for 1980s vintage plants in 1986 is due to high costs at a single plant. Because there are only a few plants in this vintage, one plant's performance can significantly affect the average for all plants.) The generally poor nonfuel O&M performance of the older units can be explained in part by their infrequent use. In 1997, plants in the 1950s and earlier vintage categories were operated at 10-percent utilization, less than half the 24-percent average utilization of all oil and gas steam plants. In a sense these plants are in a "catch-22" situation: they are used infrequently because they have relatively high costs, and their infrequent use drives up their average per-kilowatthour nonfuel O&M costs. The fuel cost distribution by vintage category narrowed considerably over the entire time period. In 1981 the range was 2.6 cents per kilowatthour, but by 1997 it had narrowed to about 0.6 cents per kilowatthour (Figure 15).

Looking at oil and gas steam plants by size also showed the expected results—the smaller, older plants tend to be

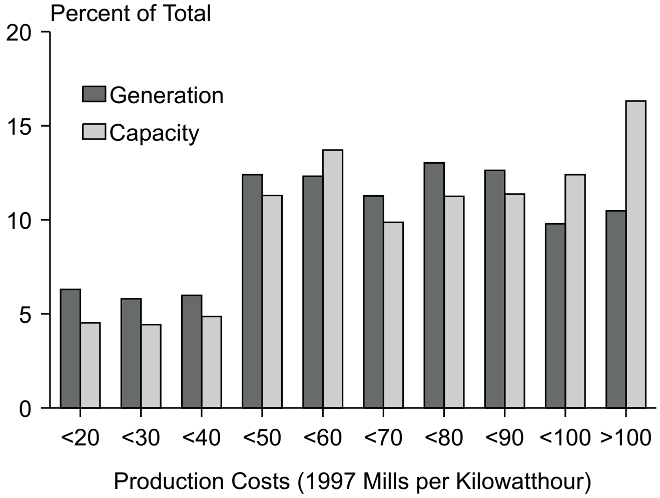
[13] Note that many of the older oil and gas steam plants brought into service in the 1950s and earlier have been retired in recent years.

Table 4. Retirement of Oil and Gas Steam Capacity by Plant Vintage, 1990-1996
(Megawatts)

Retirement Year	Plant Vintage			
	1950s	1960s	1970s	All Vintages
1990	132	—	—	132
1991	721	326	—	1,047
1992	348	11	—	359
1993	890	16	—	906
1994	1,812	—	—	1,812
1995	255	304	—	559
1996	793	—	93	886
Total	**4,950**	**657**	**93**	**5,701**

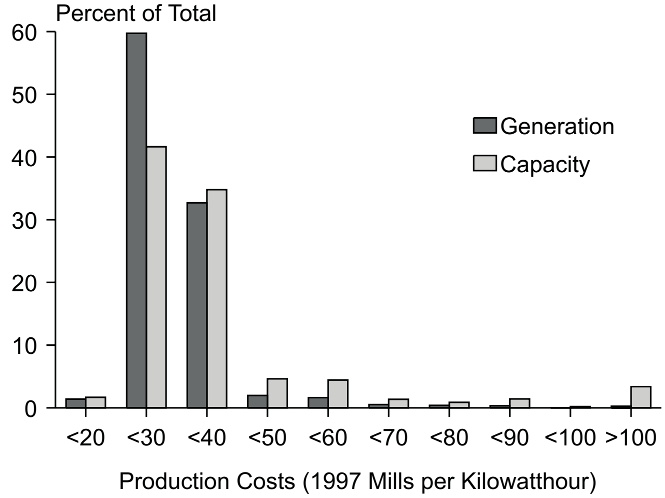
Source: Energy Information Administration, Form EIA-860, “Annual Electric Generator Report” (1997).

Figure 12. Distribution of 1981 Oil and Gas Steam Plant Production Costs



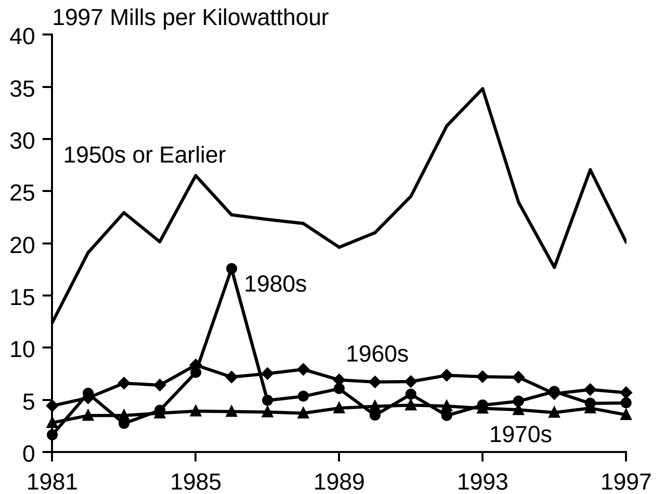
Sources: FERC Form 1, “Annual Report of Major Electric Utilities, Licensees and Others,” and Form EIA-412, “Annual Report of Public Electric Utilities” (1981-1997).

Figure 13. Distribution of 1997 Oil and Gas Steam Plant Production Costs



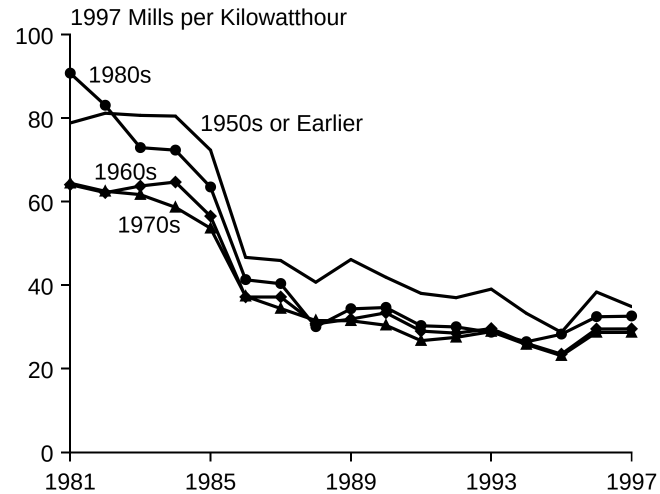
Sources: FERC Form 1, “Annual Report of Major Electric Utilities, Licensees and Others,” and Form EIA-412, “Annual Report of Public Electric Utilities” (1981-1997).

Figure 14. Oil and Gas Steam Plant Nonfuel Costs per Kilowatthour by Vintage, 1981-1997



Sources: FERC Form 1, “Annual Report of Major Electric Utilities, Licensees and Others,” and Form EIA-412, “Annual Report of Public Electric Utilities” (1981-1997).

Figure 15. Oil and Gas Steam Plant Fuel Costs per Kilowatthour by Vintage, 19891-1997



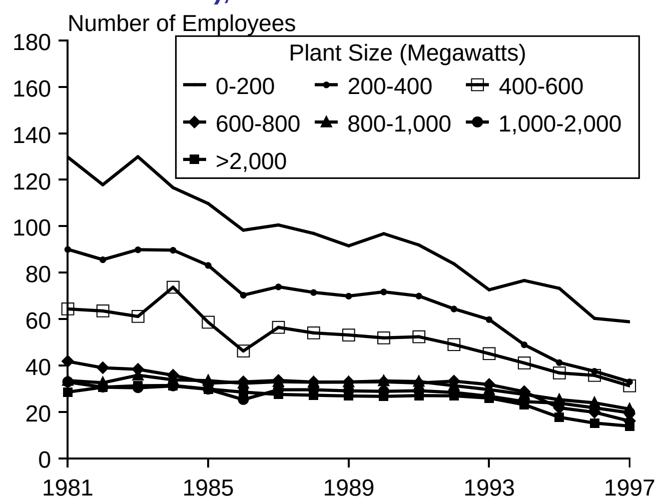
Sources: FERC Form 1, “Annual Report of Major Electric Utilities, Licensees and Others,” and Form EIA-412, “Annual Report of Public Electric Utilities” (1981-1997).

more costly. As mentioned, these older, smaller units typically are used very infrequently. Over the 1981 through 1997 period, capacity factors for oil and gas steam plants declined for all plant sizes, with the largest—those greater than 2,000 megawatts—falling from 43-percent utilization to 24 percent. Mid-sized plants—from 600 to 800 megawatts—declined from 37 percent to 29 percent, and the smallest—200 megawatts and smaller—declined from 29-percent utilization to 10 percent (Figure 16).

As with coal plants, employment per megawatt at oil and gas steam plants has also dropped, especially since 1993. After holding steady in a range between 27 and 33 employees per 300 megawatts from 1985 through 1992, plants greater than 600 megawatts reduced their employment by one-third to as much as one-half. By 1997, the largest oil plants were down to about 13 employees per 300 megawatts of capacity, although the smallest plants still had nearly 60 employees per 300 megawatts of capacity (Figure 17). Together, the two supervisory labor components of nonfuel O&M[14] declined by about 20 percent.

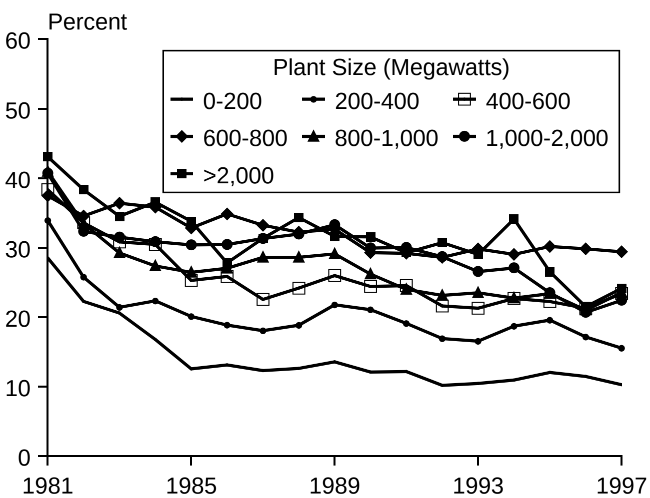
Most specific nonfuel O&M categories increased over the first 10 years of the 1981-1997 period but have been in decline since 1992 (Figure 18). For example, costs incurred for maintenance on boiler, the single largest nonfuel O&M expense, increased by 36 percent between 1981 and 1991 but have since declined by 35 percent. The story is similar for maintenance on electric plant, the second largest expense, which has fallen on average by 34 percent over the same period. When indexed to 1981 levels, the pattern of change over the entire period emerges. Over the first part of the period, costs other than fuel costs rose; but beginning in the late 1980s and early 1990s, most began to fall. Even with the decline seen in recent years, however, only two categories of nonfuel O&M costs—maintenance on the boiler and the electric plant, the two largest nonfuel cost categories—are below 1981 levels (Figure 19).

Figure 17. Oil and Gas Steam Plant Employees by Plant Size (Average for a 300-Megawatt Plant), 1981-1997



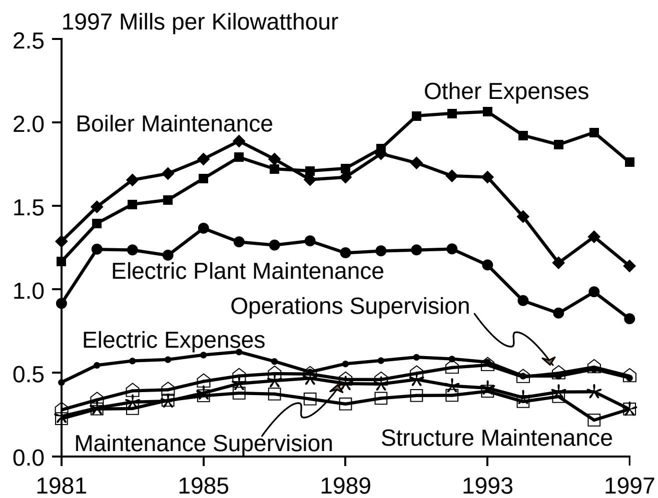
Sources: FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others," and Form EIA-412, "Annual Report of Public Electric Utilities" (1981-1997).

Figure 16. Oil and Gas Steam Plant Average Capacity Factors by Plant Size, 1981-1997



Sources: FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others," and Form EIA-412, "Annual Report of Public Electric Utilities" (1981-1997).

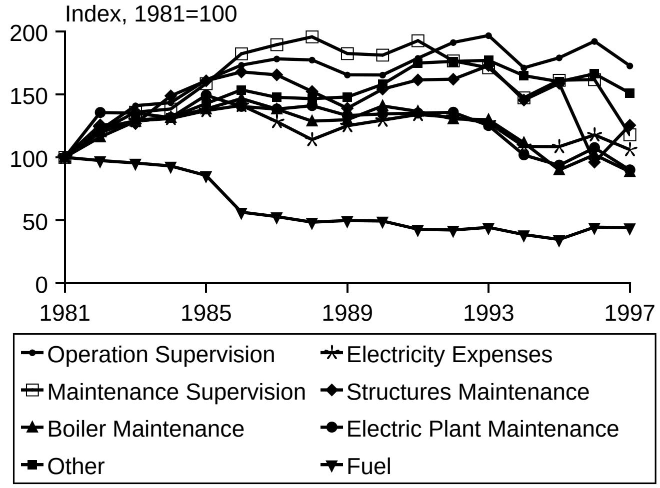
Figure 18. Oil and Gas Steam Plant Nonfuel Production Costs by O&M Category, 1981-1997



Sources: FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others," and Form EIA-412, "Annual Report of Public Electric Utilities" (1981-1997).

[14] Maintenance supervisory engineering and operations supervisory engineering.

Figure 19. Oil and Gas Steam Plant Production Costs by O&M Category, 1981-1997



Sources: FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others," and Form EIA-412, "Annual Report of Public Electric Utilities" (1981-1997).

Summary

Because of the improvements in production costs that have occurred over the past 17 years, existing coal plants are now very economical. Their average production costs—1.8 cents per kilowatthour—make them among the lowest cost plants operating today. In addition, coal prices are expected to continue to fall, although at a somewhat slower rate, in the future. In the *Annual Energy Outlook 1999*, delivered coal prices to power plants are expected to decline by another 27 percent between 1997 and 2020. Although this is a significant decline, it is smaller than the 51-percent decline that occurred between 1981 and 1997.

With respect to nonfuel O&M costs the potential for further declines is less clear. The per-kilowatthour nonfuel O&M costs for coal plants fell by 32 percent between 1981 and 1997, but a good portion of the decrease was due to the 21-percent increase in utilization of the plants rather than to cost improvements. Recent EIA analyses indicate that the trend toward growing utilization of coal plants is expected to continue. In addition, based on the historical improvement, it is assumed that O&M costs will fall by another 25 percent over the next decade.[15] There remains considerable dispersion in nonfuel O&M costs among the plants, which could motivate improvements in the higher cost units. Because of the assumed improvements, by 2020, the average production costs of coal steam plants could be as low as 1.3 cents per kilowatthour.

With respect to oil and gas steam plants the future is less promising. Although their operating costs fell significantly between 1981 and 1997, they remain uneconomical in comparison with coal plants and other new plant options. Their total per-kilowatthour operating costs in 1997 are nearly twice those for coal plants. The relatively high operating costs of oil and gas plants have led to their declining generation over the 1981 through 1997 period. This decline in utilization is expected to continue as many of these units are retired when they are displaced by more efficient natural gas combined-cycle plants.[16]

[15]Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998).
[16]Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998).

Sectoral Pricing in a Restructured Electricity Market

by
Peter Whitman

Historically, electricity prices have not been determined by the competing interests of suppliers and consumers in open markets. Rather, State regulators have set prices by reviewing the costs incurred by the utilities under their jurisdiction, using both equity and economic efficiency as criteria to determine how costs should be allocated to different customer groups. Restructuring of the electric utility industry has the potential to significantly alter the relationship between the prices paid by different customer classes. This paper presents a framework for evaluating price differentials among customer classes and quantifies such differences with the introduction of a regulatory preference parameter. It then explores how the prices paid by different groups may change as the generation sector of the electric power industry becomes more competitive.

Introduction

The emergence of competitive markets for generation in the electricity industry has created the potential for a new alignment of costs and benefits among classes of utility customers. From a purely economic perspective, it is well established that the "optimal" price of electricity equals the marginal cost of generation, transmission, and distribution. In the electric power industry, however, because the costs of transmission and distribution decline with the volume of service provided, setting price equal to marginal cost may fail to generate enough revenue to recoup the total costs. To avoid this problem, rates have traditionally been set by regulators based on the average cost of producing electricity and serving the customer, including both short-run costs such as fuel and long-run costs such as plant and capital recovery.

Historically, average cost pricing has been seen as a way of ensuring that revenues cover total costs. Although optimality may be defined as efficient in a strictly economic sense, many other considerations, such as equity and simplicity, play a role in rate-setting, leading to different rates by customer class. This paper provides a framework for evaluating rate differentials under rate-of-return regulation and explores some possible outcomes when customer choice is allowed.

Background

The changing nature of the electric utility industry will undoubtedly modify the burden of costs among customer classes. The generation component of the electricity market is being separated from transmission and distribution. While nearly all customers are expected eventually to benefit from the introduction of competition in the generation function, the rate and degree of such benefits may vary by customer class.[1] Regulators' goals in terms of efficiency and equity are not expected to change, but their ability to act upon those preferences may change as prices become more market-based.[2] Competition may introduce new products and services as markets are restructured, and firms may have incentives to change their pricing to meet specialized demands.

An analogy may be seen in the U.S. natural gas market for transmission services, where restructuring resulted in a wider array of options for some customers. In particular, those customers with more flexibility in their transmission and distribution requirements were in a position to find less expensive service.[3] Those users, primarily large industrial consumers, benefitted most from the restructured natural gas market. Figure 1 shows the transmission and distribution markup (the difference

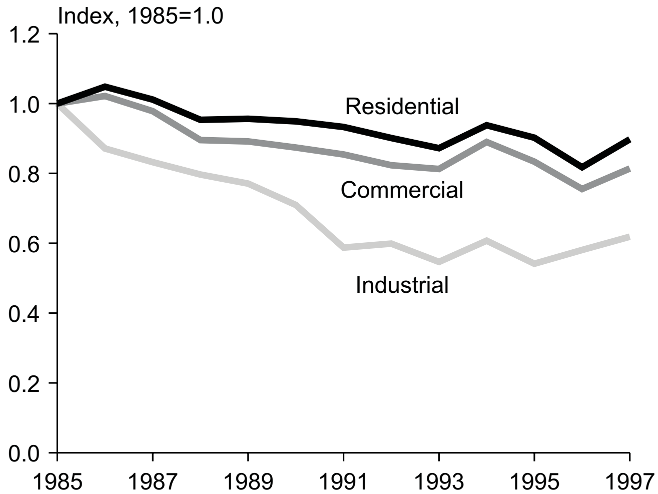
[1]It is likely, however, that customer classes will vary from their traditional designations and will be defined by load size and consumption patterns.

[2]The ability of regulators to act upon their preferences will depend on the structure of the market and the decisions of various States on how to manage such transition issues as allocation of stranded costs. Many States have included mandated rate reductions as part of the transition to a competitive market. For instance, both California and Massachusetts have mandated reductions in residential rates while the transition period is in effect. See, for instance, web site www.eia.doe.gov / cneaf / electricity / chg_str / tab5rev.html.

[3]Energy Information Administration, *Natural Gas Annual 1991*, DOE / EIA-0131(91) (Washington, DC, October 1992).

between the wellhead and end-use prices of natural gas) by sector from 1985 to 1997, indexed to 1985.[4] As shown, the average price of transmission and distribution for industrial users declined significantly more (on a percentage basis) than that for residential users.

Figure 1. Index of Real U.S. Natural Gas Transmission and Distribution Markups by End-Use Sector, 1985-1997



Source: Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998), and *Natural Gas Annual 1997*, DOE/EIA-0131(97) (Washington, DC, October 1998).

While a portion of these sectoral price differentials can be attributed to differences in the cost of service, a substantial fraction can only be accounted for by price discrimination. Price discrimination can be defined as selling two or more varieties of a commodity to two or more buyers at different net prices, the net price being the price paid by the buyer, corrected for cost or quality differences. Given this definition, price discrimination is a ubiquitous phenomenon in that most firms sell several varieties of products at prices that do not fully reflect their differences in quality or cost. For example, the practice of most supermarkets of providing shoppers with coupons is a form of price discrimination, because customers who save and use the coupons pay a lower price than those who do not. Another example of price discrimination is the airline industry practice of charging lower fares to passengers who stay over Saturday night in a destination city. Individuals who do not stay over are presumed to be traveling on business and thus are judged to be relatively price insensitive. Those who do stay over are presumed to be traveling for pleasure and thus to be more concerned with the price paid.

There are two main reasons for rate differentials in regulated markets. The first is that, as in most markets, customers vary in terms of their demand elasticity (i.e., their sensitivity to price), and regulators respond to the differences by offering the lowest prices to the most price-sensitive customers. A countervailing influence in a regulated market is equity considerations. Unbridled price discrimination based on demand elasticities alone may result in price differentials that are "unfair and unreasonable." To achieve a more equitable solution, regulators may order the firm to modify its pricing strategy. While both of these motivations for price discrimination may still be present in the restructured electricity industry, the changing form of the market is likely to make the rate structure more responsive to market forces.

Pricing in Fully Regulated Markets

Consider a monopolist generator / distributor of electricity that provides service to three distinct customer classes: residential, commercial and industrial, where prices are set by the regulator. We divide the cost of electricity into its three major components: production, transmission, and distribution. In many cases the marginal cost of electricity is below the average cost. That is, if every customer class were charged its incremental cost of service, a utility would not cover its total costs. It is economically most efficient to recover this deficit through a lump-sum payment from general funds. This approach would cause the least deviation from marginal costs. However, regulators typically have found it infeasible to recoup all costs in this manner. Therefore, allocation of such costs over and above the incremental costs are decided by regulators. Such allocations, translated into rates, may be considered a form of price discrimination. Price discrimination in this sense is inherent in the development of traditional electricity rates.

Given the traditional market structure of a regulated monopoly, a second-best framework is a pricing approach whereby classes of customers with inelastic demands pay a higher markup over marginal cost than those with more elastic demands. This is generally referred to as "Ramsey pricing." The goal of this pricing strategy is to recoup the fixed costs while minimizing the distortion associated with prices in excess of marginal costs. Under Ramsey pricing, customers with the most inelastic demands pay the highest markup over marginal cost. Because those customers have the fewest options, their consumption is reduced the least. That is, the least deviation of consumption from marginal cost pricing is achieved by using this general rule. Given the constraint that the firm cannot operate at a loss, economic efficiency is attained through the use of Ramsey pricing.

[4]It is likely that Figure 1 underestimates the difference between industrial and other customers, as the industrial customer data reflect only the subset that have not chosen to leave their local distribution companies.

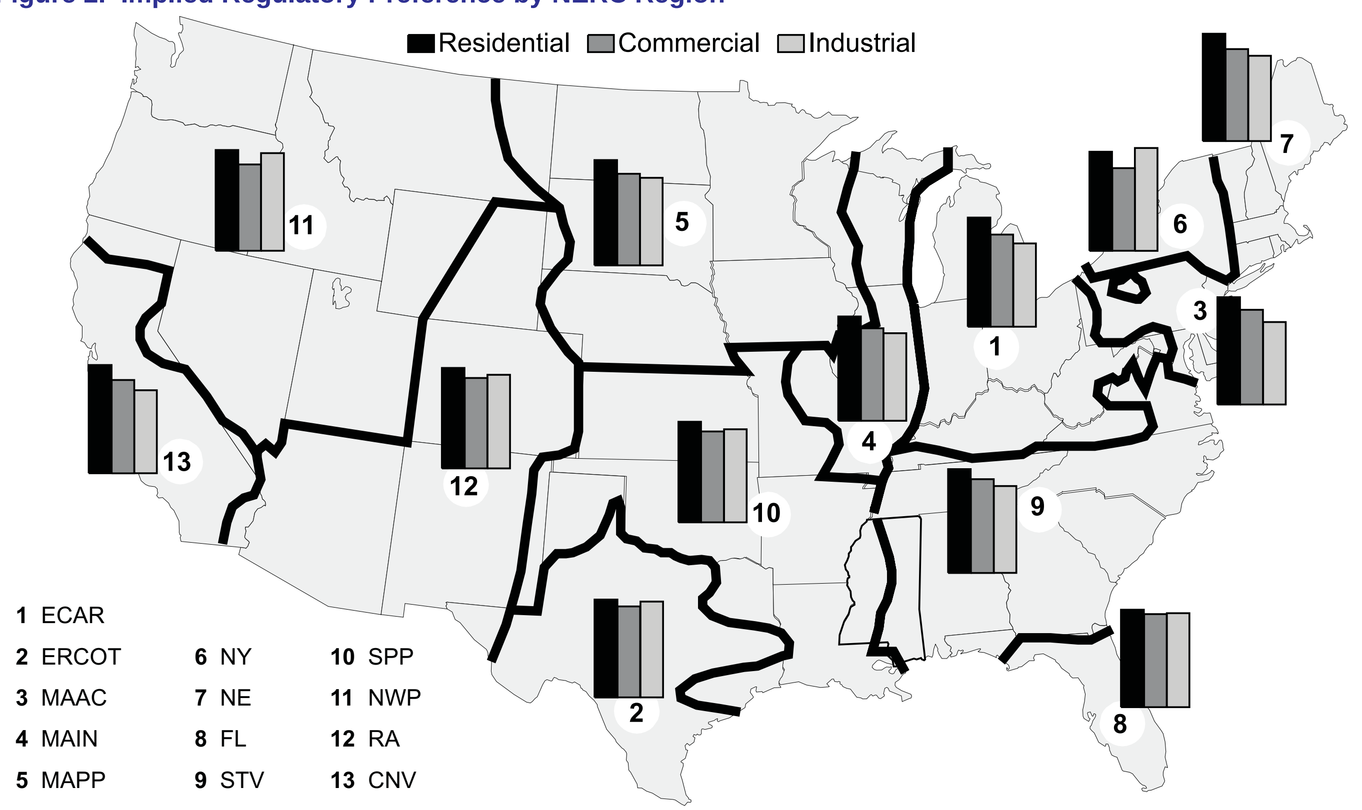
The theoretical optimality of the Ramsey inverse elasticity pricing rule depends on a number of assumptions. The most important is that society considers only economic efficiency and that, as a result, it is indifferent to whether the pricing structure is "fair" and "reasonable." Since, in general, equity considerations are important, policymakers may deviate from the economically efficient outcome so as to avoid imposing "unreasonably" high prices on groups with inelastic demands.

One way of incorporating such deviations is to explicitly represent the preferences of regulators in terms of equity in the Ramsey framework. We define the price-cost margin as the ratio of the price less marginal costs relative to the total price. The price-cost margin then represents the degree to which the price exceeds marginal cost. Under the Ramsey pricing model, consumer surplus is maximized when the price-cost margin is inversely proportional to the sectoral elasticity. We can extend this framework by attributing different weights to the consumer surplus of each sector. Maximizing the weighted consumer surplus, subject to the constraint that total costs must be covered, yields the implied regulatory preference.

We can draw two major conclusions from the results of this extended model. First, the price-cost margin varies inversely with the absolute value of the price elasticity of demand. That is, those customers with the least response to price have the highest price-cost margin. Second, the implied regulatory preferences will affect the difference between price and marginal cost. Specifically, if the decisionmaker attaches zero weight to the interests of a specific customer class, then that customer class faces the monopoly price. As the implied weight that the regulator attaches to the customer class increases, the price for that customer class declines, approaching marginal cost. The mathematical representation of these preferences is shown in the Appendix.

By comparing the results of such a model with historical prices, one can deduce the implied regulatory preferences. Figure 2 shows the estimates of such preferences for the residential, commercial, and industrial sectors based on historical prices by North American Electric Reliability Council (NERC) region. For each region three bars are shown, one for each sector. The scale is relative. A higher value represents a greater implied regulatory preference for that sector; lower values represent less implied preference. The preference is inversely proportional to prices, with a higher preference indicating greater regulatory preference and thus lower prices. Figure 3 compares actual prices of electricity by customer class in 1997 with an estimate of economically

Figure 2. Implied Regulatory Preference by NERC Region

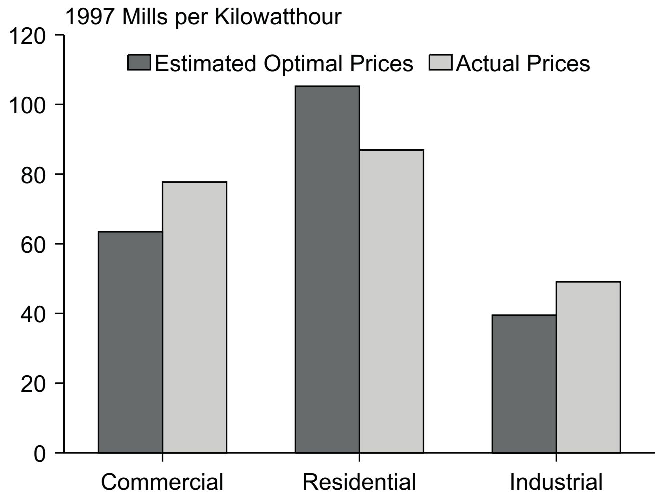


Note: Bars represent comparative preferences among customer classes within each region. They are not comparable across regions.

Source: National Energy Modeling System, runs AEO99B.D100198A and COMPETE.D100398A.

optimal prices. That is, the implied regulatory preference is set to unity across all sectors. The results indicate that industrial and commercial prices in 1997 were largely higher and residential prices lower than the prices associated with the economically optimal Ramsey solution.

Figure 3. Actual 1997 Electricity Prices by Sector and Calculated Prices with Optimal Pricing



Source: National Energy Modeling System, runs AEO99B.D100198A and COMPETE.D100398A.

Pricing with Competitive Generation

Assume that electricity is distributed under rate-of-return regulation as before, but the generation component is now competitively priced. Assume further that the regulatory preferences remain the same in the restructured environment. There are three customer classes: residential, commercial, and industrial, each with varying characteristics. Some sectors, such as residential, have little ability to leave the distribution system and thus have low elasticities. Others, such as industrial customers, have a much higher elasticity and the ability to bypass the system. In this sense, "bypass" refers to the ability to generate electricity on site, relocate, or otherwise withdraw from the local system. We assume that the demand for bypass is positively related to the price of distribution; that is, as the price increases the usage decreases, and the desire to bypass the system is increased.

Given these circumstances, regulators must look to modify their pricing algorithms. In a restructured environment where competition for generation is introduced, the generation component of electricity price is necessarily beyond the regulator's control; only the pricing of transmission and distribution functions remains regulated. Because transmission and distribution services are only a portion of the total price of electricity, the impact of apportioning their fixed costs among customer classes on the total price will be smaller than when all fixed costs—for generation, transmission, and distribution—are included. If the price paid by a particular class is set equal to the marginal cost, that group contributes nothing to the fixed costs. As the price rises above this level, the group contributes to the fixed costs but only to the extent that it remains on the system.

The sectoral distribution price is a function of the elasticity of the customer class and the implied regulatory preference as before. However, three additional factors must be included: the price of the generation component, the fraction of load available for bypass, and the elasticity of bypass. While generation is purchased competitively, and thus its price is set by the market rather than through regulation, its level affects the overall price and the ultimate consumption by the customer class. The elasticity of bypass represents the willingness of the customer class to explore bypass opportunities as the price rises and as the fraction of load for which bypass may be available increases. Both a larger elasticity of bypass and a larger fraction of load available for bypass would tend to cut consumption from the grid as the price rises. As long as the price of distribution is above marginal cost, it is worthwhile to continue to supply service. As the share of potential bypass candidates decreases, the price charged approaches that which might be set if no bypass were available. Similarly, the price declines as the elasticity of bypass increases. This model provides a framework for analysis, given a regulated distribution system and customers with different elasticities and abilities to avoid the distribution system. The mathematical representation of such a market structure is shown in the Appendix.

Applications in the *Annual Energy Outlook 1999*

The *Annual Energy Outlook 1999* (*AEO99*) incorporated the effects of restructuring in sectoral electricity price projections. Figure 4 compares the sectoral prices projected in the *AEO99* full competition and reference cases for the Electricity Cooperative Agreement for Reliability (ECAR) NERC region, which comprises the States of Ohio and Indiana, the Lower Peninsula of Michigan, and parts of Pennsylvania, West Virginia, Virginia, and Kentucky. Prices in the ECAR region decline throughout the projection period due to declining coal prices, declining capital expenditures, and improved efficiencies of new plants.

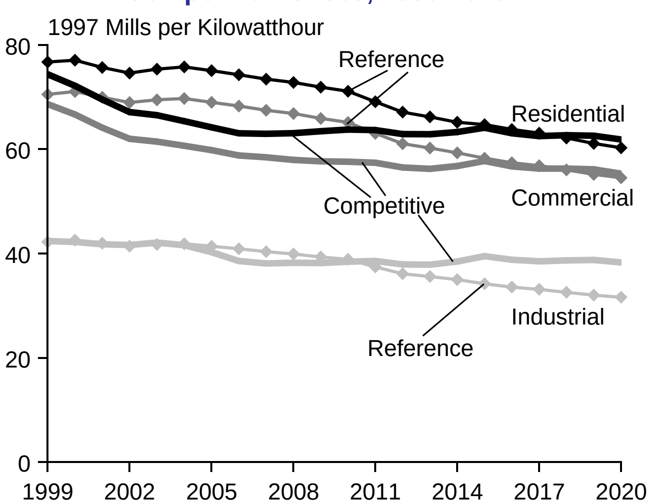
In the full competition case, generation is priced on a marginal cost basis. In the early years of the projection, the marginal cost of generation is below that of the generation component of price under rate-of-return regulation. Therefore, the price of electricity falls as stranded cost recovery is completed. The reduction has the greatest impact on the residential and commercial sectors, which bear the largest absolute portion of the generation price. In the last years of the projection, the marginal cost of generation increases slightly, reflecting both the increasing price of natural gas and the greater proportion of time that the relatively more expensive natural-gas-fired plants set the margin over less expensive coal-fired units. As a result, the prices for all three sectors in the competitive case are flat over the last 10 years of the projection. The reference case prices continue to decline, dropping below those in the competitive case by 2020.

It was assumed that, through the function of an Independent System Operator (ISO) or other market structure, the generation component of price at any one instant would be equal for all customers. That is, the difference between the average yearly price of the generation component of electricity for different customer classes depends only on the fraction of their annual load purchased during high-priced periods. This had the effect of causing prices to decline most rapidly in the residential and commercial sectors under competition as compared with the reference case, as generation was a larger fraction of their total price.

The near equivalence of the generation prices is illustrated by the representative price-duration curve shown in Figure 5, which depicts the ranked hourly price of electricity from the most expensive to the least expensive hour. The key feature of the graph is that the price-duration curve is relatively flat on a per-kilowatthour basis. A flat curve shows that, except for a limited number of peak hours, the price of generating electricity is relatively constant. Accordingly, in a fully competitive market, the average annual price of electricity is similar for customers with relatively flat requirements as compared to those with large peaks in their demands. The differences reflect different levels of consumption among the customer classes in the peak periods. Generation costs for different customer classes are shown in Figure 6.

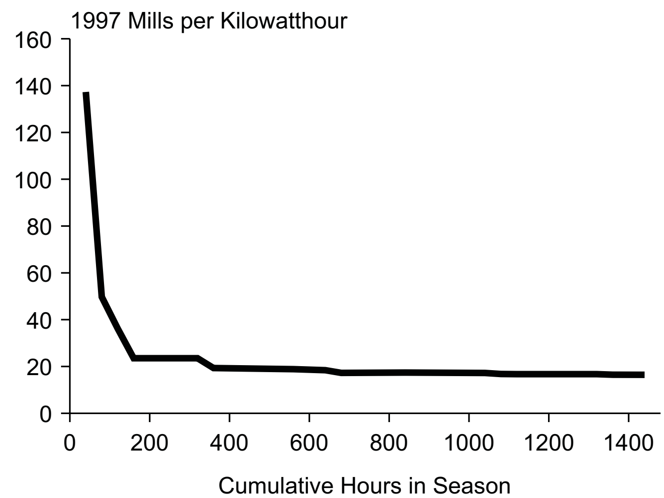
The model discussed here assumes that, while both transmission and distribution will continue to be under the purview of regulators, the unbundling of generation from transmission and distribution will provide medium and large consumers with a greater ability to obtain price concessions from the operator of the

Figure 4. ECAR Electricity Prices by End-Use Sector in the Reference and Full Competition Cases, 1999-2020



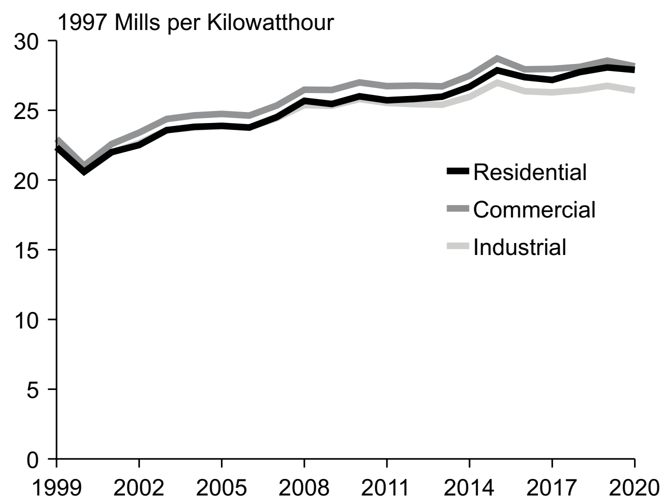
Source: National Energy Modeling System, runs AEO99B. D100198A and COMPETE.D100398A.

Figure 5. ECAR Electricity Generation Price Duration Curve



Source: National Energy Modeling System, run COMPETE. D100398A.

Figure 6. Generation Component of ECAR Electricity Prices by End-Use Sector, 1999-2020



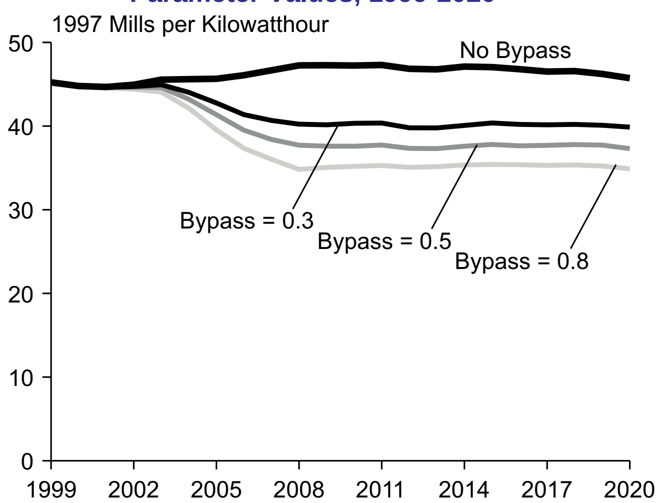
Source: National Energy Modeling System, run COMPETE. D100398A.

distribution system. Specifically, under the new market structure some consumers may have the ability to bypass the distribution system at relatively low cost by connecting directly to the transmission system or building an on-site generator. Concessionary pricing—i.e., changes in the allocation of fixed costs among the customer classes—may be necessary to retain those customers. The equations in the Appendix reflect the effect of concessionary pricing on the sectoral distribution of prices.

The ability to bypass the distribution system, or to credibly threaten such bypass, is the most important factor in determining the level of price concessions. The level depends on a number of factors, including the projected cost of distributed generation technologies, fuel costs at the distributed generation site, and the regulatory regime under which distributed generation may occur. Bypass has been parameterized as the fraction of load with the potential to bypass the distribution system. Figure 7 shows the national level of industrial prices under competition with several values of the bypass parameter. With bypass restricted, industrial prices may rise above those in the reference case. As more of the industrial load has the potential for bypass, the industrial price declines.

Figures 8, 9, and 10 again compare the sectoral prices in the reference case with those in the full competition case, including concessionary pricing of transmission and distribution. As a counterpoint, another projection is shown, based on the assumption that industrial customers would be unable to obtain any additional concessions from the operators of the transmission and distribution system (no concessionary pricing). As can be seen, if average generation prices by customer class

Figure 7. Industrial Prices Under Four Bypass Parameter Values, 1999-2020

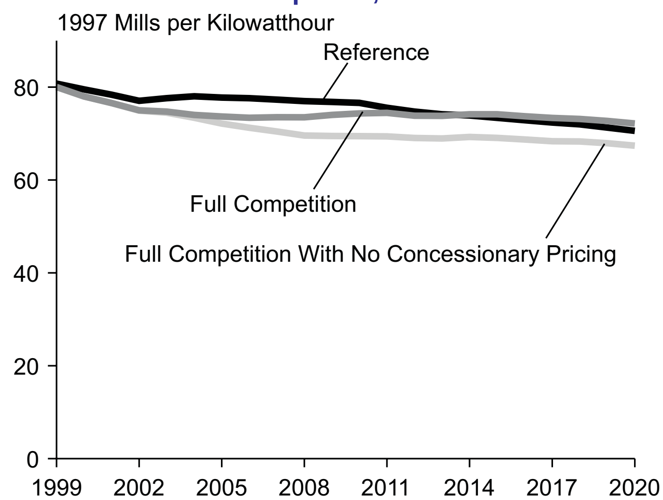


Source: National Energy Modeling System, runs COMPETE.D100398A, NOBYPASS.D061199B, BYPASS5.D060199B, and BYPASS8.D060199B.

tend to converge, it is possible that industrial end-use prices could rise significantly above the reference case price unless there was a reallocation of costs within the regulated transmission and distribution sector. Such an increase in the industrial price would cause a concomitant decrease in residential and commercial prices.

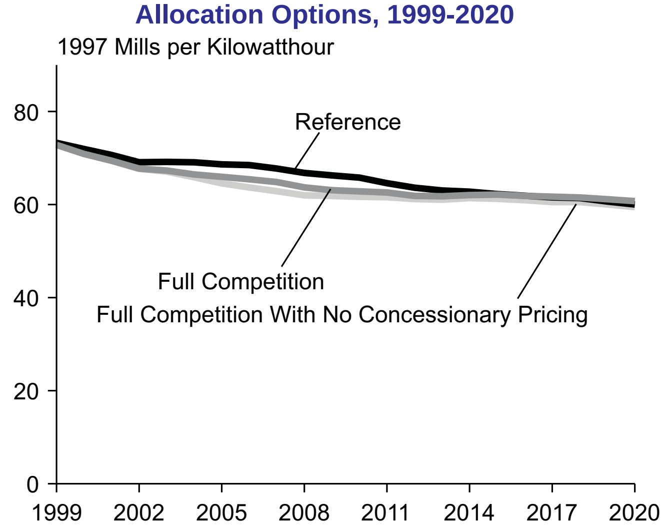
Given that similar efficiency improvements are assumed in the reference and full competition cases, it is not surprising that the national sectoral price projections in the two cases are similar. However, this analysis assumes that, if price discrimination is not present in the

Figure 8. Residential Electricity Prices in the ECAR Region Under Three Fixed Cost Allocation Options, 1999-2020



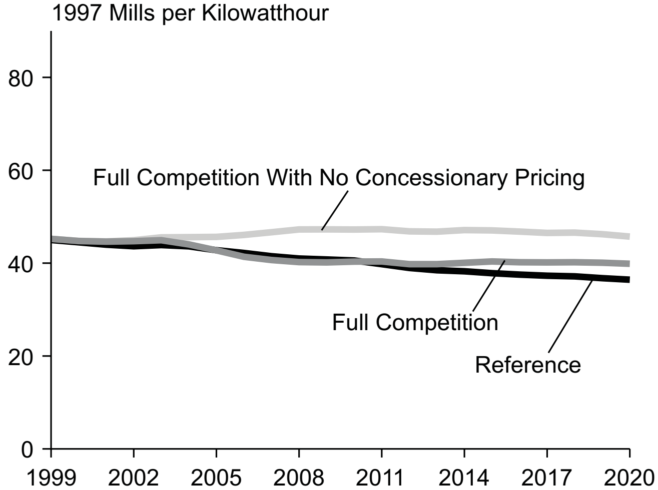
Source: National Energy Modeling System, runs COMPETE.D100398A, AEO99B.D100198A, and NOBYPASS.D061199B.

Figure 9. Commercial Electricity Prices in the ECAR Region Under Three Fixed Cost Allocation Options, 1999-2020



Source: National Energy Modeling System, runs COMPETE.D100398A, AEO99B.D100198A, and NOBYPASS.D061199B.

Figure 10. Industrial Electricity Prices in the ECAR Region Under Three Fixed Cost Allocation Options, 1999-2020



Source: National Energy Modeling System, runs COMPETE.D100398A, AEO99B.D100198A, and NOBYPASS. D061199B.

competitive generation market, larger customers will maintain their ability to achieve lower rates in the remaining regulated portions of the industry.

Conclusion

Restructuring will undoubtedly present new challenges to the portions of the electric utility industry that remain regulated. It is likely that the pattern of prices among sectors will change in the new environment. While the regulatory goal of fair and equitable rates remains, the ability to act on that goal may be adversely affected by restructuring. The results shown here indicate that industrial and commercial prices could be largely higher, and residential prices lower, than the prices associated with an economically optimal solution. A comparison of the *AEO99* reference and full competition cases for a single region shows that, without concessionary pricing, industrial prices under competition could be significantly above those under traditional rate-of-return regulation.

Appendix

Suppose that a regulator sets prices for a firm so as to maximize a weighted sum of consumer surpluses over the customer classes served by the firm. Specifically, assume that there are three customer classes, and the decisionmaker maximizes the sum of $\theta_i CS_i$, where CS_i is the consumer surplus of customer class i and θ_i is the weight that the decisionmaker attaches to i's level of welfare. The case in which the decisionmaker is indifferent to the welfare of i is represented by $\theta_i = 0$. The case in which the economic interests of i are twice as important as those of j can be represented by $\theta_i = 2$ and $\theta_j = 1$.

Our model is then:

$$Max\ \theta_1 CS_1 + \theta_2 CS_2 + \theta_3 CS_3 \ , \qquad (1)$$

such that:

$$P_1 X_1 + P_2 X_2 + P_3 X_3 - C(X_1, X_2, X_3) = 0 \ . \qquad (2)$$

This merely states that the regulator attempts to maximize the weighted consumer surplus subject to the constraint that the revenues for the regulated utility must equal its costs. An unconstrained maximization problem may be formed with the addition of Lagrange multipliers, to determine a solution that satisfies the first-order conditions. The solution is:

$$\frac{P_i - C_i'}{P_i} = \frac{1 - \theta_i / \lambda}{|\varepsilon_i|} \ , \qquad (3)$$

where ε_i is sector i's price elasticity of demand, λ is a scalar to preserve feasibility of the solution, and $C_i' = \partial C(X_1, X_2) / \partial X_i$ is the marginal cost of production.

Now assume that the electricity is distributed by a regulated natural monopolist. We have three sectors: residential, commercial, and industrial. Each sector purchases X_i from the generating industry at the price PG_i per unit. Assume that the total cost of distribution is related to the amount of power distributed to each sector, i.e., the total cost of distribution is $C^D(X_1^S, X_2^S, X_3^S)$ where X_i^S is the amount of power that the distributor delivers to sector i through its system.

In *AEO99*, the industrial and commercial sectors were assumed to have the threat of bypass—i.e., the ability to leave the system through self-generation or other means. We let $X_i^S = X_i - X_i^B$, where X_i^B is the amount of power that bypasses the distribution system. Let η represent the elasticity of nongrid supply, i.e., $\eta = \partial X_i^B / \partial P_i)(P_i / X_i^B)$, and let S_i^D be the share of total generation purchased by the sector i that uses the distribution system (i.e., $S_i^D = X_i^S / X_i$), where $i = 2$ for commercial and 3 for industrial. In contrast, the residential sector must purchase all its power through the local distribution system. Assume that the amount of power bypassed is positively related to the end-use price of electricity, i.e., $\partial X_i^B / \partial P_i > 0$, where P_i is the total end-use price. Finally, assume that the end-use price is the sum of the generation price (PG_i) and the distribution charge (PD_i).

Based on the above discussion, the decisionmaker is assumed to maximize the function:

$$\begin{aligned} L &= \theta_1 CS_1 + \theta_2 CS_2 + \theta_3 CS_3 \\ &\quad + \lambda[PD_1 X_1^S + PD_2 X_2^S + PD_3 X_3^S \\ &\quad - CD(X_1^S, X_2^S, X_3^S)] \ . \end{aligned} \qquad (4)$$

For the customers in the residential sector, $X_j^S = X_j$, and thus the following result can be obtained:

$$PD_j = \frac{CD_j' |\varepsilon_j| + PG_j (1 - \theta_j / \lambda)}{|\varepsilon_j| - (1 - \theta_j / \lambda)} \ . \qquad (5)$$

In the sectors where bypass is possible, the distribution price for sector i can be shown to equal:

$$PD_i = \frac{\frac{C_i^{D\prime}}{S_i^D}[|\varepsilon_i| + \eta_i (1 - S_i^D)] + PG_i (1 - \theta_i / \lambda)}{\frac{1}{S_i^D}[|\varepsilon_i| + \eta_i (1 - S_i^D)] - (1 - \theta_i / \lambda)} \ . \qquad (6)$$

We can see that Equation (6) reduces to Equation (5) when S_i^D equals 1, that is, when no bypass is possible.

Modeling the Costs of U.S. Wind Supply

by
Thomas W. Petersik

Renewable energy sources, including wind power, are increasingly seen as a way of meeting the Nation's energy requirements while also contributing to carbon emissions reductions, promoting fossil fuel conservation, and reducing other harmful pollutants such as sulfur dioxide and nitrogen oxide. However, renewables can also be more expensive, and by their nature some are not always available to meet baseload electricity demands. This paper describes the methodology used in the National Energy Modeling System (NEMS) for representing electricity generation from wind power, one of the more mature and lower cost renewable energy technologies, and one that has been prominently mentioned as a means of helping to meet the Kyoto Protocol's carbon reduction targets for the United States.

Introduction

Existing wind power capacity in the United States today is approximately 2,000 megawatts—about 0.2 percent of all U.S. grid-connected electricity generating capacity—and accounts for about 0.1 percent of generation.[1] As a carbon-free technology, however, wind power is increasingly discussed for its potential in meeting U.S. and global carbon reduction targets, such as those proposed in the 1998 Kyoto accords. Wind technology does not have fuel requirements as do coal, gas, and petroleum generating technologies; however, both the equipment costs and the costs of accommodating special characteristics such as intermittence, resource variability, competing demands for land use, and transmission and distribution availability can add to the costs of generating electricity from wind.

The purpose of this paper is to describe how the Energy Information Administration (EIA) addresses in the National Energy Modeling System (NEMS) the natural resource, transmission and distribution, and market factors that affect the cost of U.S. electricity generation from wind resources. This introduction summarizes general electricity modeling in NEMS. The second section, "Representing Wind Generating Technology," outlines the overall NEMS representation of wind, including identification of the cost adjustment factors. The third and fourth sections, "Basis for Wind Cost Adjustment Factors" and "Cost Adjustment Factors for U.S. Wind Supply,"provide EIA's justification for and derivation of the cost adjustment factors. The sections show applications of the factors in recent EIA forecasts for wind power, identify key issues for further examination, and conclude by summarizing the importance of the issue of cost.

NEMS is an integrated computer model of the U.S. energy economy. It includes modules representing all the major supply and demand sectors that produce and consume energy. Within NEMS, the selection of new generating capacity, including wind, is based on the relative costs of competing technologies. Electricity generating technologies compete based on capital, fuel, and operations and maintenance (O&M) costs for providing U.S. regional baseload, intermediate, and peaking electric power supply. Intermittent technologies such as wind also compete on their ability to meet electricity demand at the time winds are available.

Capital costs for all generating technologies are affected by a number of characteristics. Using information from the Department of Energy, the Electric Power Research Institute, published reports, meetings with industry and technology representatives, and others, EIA estimates the initial capital cost for each technology.[2] Capital costs decrease as experience with the technology increases (learning-by-doing effects), and as domestic and international capacity penetrate electric power markets.[3] At high rates of growth, however, capital costs may temporarily increase in response to short-term bottlenecks.

[1]Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998), reference case AEO99B.D100198A.

[2]For example, see the Electric Power Research Institute and U.S. Department of Energy report, *Renewable Energy Technology Characterizations*, EPRI TR-109496 (December 1997).

[3]In general, capital costs in NEMS are assumed to decline by 10 percent for every doubling of U.S. capacity from the first through the fifth commercial unit, 5 percent for every doubling from the sixth through the fortieth unit, and 2.5 percent for every doubling thereafter.

Fuel costs also affect technology competition. For fossil fuels, fuel costs are projected separately in NEMS in the individual fuel supply modules, providing inputs for subsequent choices among generating technologies. In contrast, the availability and cost of wind energy—essentially its "fuel" cost—are represented in two ways. First, wind turbine capacity factors used in NEMS vary by geographic region, time of day and season, and by the estimated energy content of available winds (wind class). Second, experience indicates that the energy availability of wind turbines is also affected by other factors in addition to region, time, and wind class. EIA expresses these additional factors along with others by adjusting wind technology capital costs. The derivation of the adjustments is the primary focus of this paper.

Representing Wind Generating Technology

The methodology for projecting electricity generation from wind power consists of a series of data inputs, capacity and dispatch algorithms, and specific components for characterizing wind energy supply. Each is discussed below.

Data Inputs

The primary data inputs are existing wind generating capacity, future capacity planned by electricity producers, wind technology cost and performance characteristics, wind capacity factors, and cost adjustment factors. EIA collects information on existing capacity and that planned for the future from electric utilities and nonutilities, including independent power producers and small power producers. Planned capacity commitments include capacity under construction, under contract, mandated by law or regulation, or under commitment by an electricity producer.

Mandated new wind capacity in Minnesota and Iowa, as well as estimates of new wind capacity to be installed under State renewable portfolio standards, are included as planned capacity. In 1999, for example, more than 600 megawatts of new wind generating capacity are planned, scheduled to take advantage of the Federal renewable energy production incentive before its expiration on July 1, 1999. Proposals or goals for new capacity that have not yet resulted in firm commitments are not included as "planned."

Capital costs for new generating technologies are assumed to decline as more units enter service and experience increases. EIA derives estimates for the key cost and performance values for wind power from a variety of sources, including the Electric Power Research Institute, the Department of Energy, other industry participants, and current market data.[4]

Capacity and Dispatch Methodologies

In order to meet projected growth in the demand for electricity and to replace retiring generating units, new capacity is added over and above existing and known plans for new capacity. The essential steps in the methodology are to determine future capacity needs based on peak demands, subtract current (net of retirements) capacity from those needs, and project the types of capacity that must be built to reach the target. The technology choice is based primarily on total costs over a 30-year horizon, including capital, O&M, and fuel costs. Technology choice is also affected by subsidies and taxes, such as those associated with meeting environmental requirements. Intermittent technologies—mainly wind and solar—are special cases, because they are not always available and thus have a reduced ability to meet demands. This problem is resolved by segmenting annual electricity demand into a number of "slices," defined by season and time of day. Wind and solar compete directly for new capacity to serve those parts of the load for which they are most suited, and they are not penalized by considering overall annual demands only, for which they would be too expensive. However, because they are not always available, their credited contribution to meet the peak demand is reduced, because their inclusion reduces the overall reliability of the system. The impact of this reduction is that more fossil-fuel-fired capacity may be built to meet the reliability requirements when wind is chosen as the most economical technology.

Unlike fossil fuel technologies that can be dispatched at varying capacity factors depending on demand and marginal cost, wind power is dispatched in NEMS at specified capacity factors derived by EIA and differing by hour of the day, season, region, and wind class. Wind capacity factors are based in part on the performance of actual units and in part on the maximum performance suggested by research on characteristics of new technologies. In addition, some improvement in wind capacity factors over time is assumed as new capacity is used and electricity producers learn how to operate their units more efficiently.

Wind Energy Characterization

Wind energy is the "fuel" for wind technologies. Because wind's fuel value is partly incorporated in capital costs and is not separately priced, EIA modifies

[4]For more information on cost and performance characteristics and sources, see Energy Information Administration, *Assumptions to the Annual Energy Outlook 1999 (AEO99)*, DOE/EIA-0554(98) (Washington, DC, December 1998), pp. 59-71, web site www.eia.doe.gov/oiaf/assum99/electricity.html.

capital costs for wind projects on the basis of three key characteristics: wind class, costs of building new transmission interconnection with the existing transmission and distribution network, and cost adjustment factors. The cost adjustment factors account for variations in natural resource quality, costs of upgrading the existing network, and effects of alternative uses for lands with wind resources. For wind resources to be useful for electricity generation, the site must (1) have sufficiently powerful winds, (2) be located near existing transmission networks, and (3) be economically accessible considering additional natural resource, transmission network, and market factors.

Wind technology opportunities are first identified by regional estimates of available wind energy. The foundation of EIA's wind supply characterizations is the adaptation of standard wind supply maps provided by the Pacific Northwest Laboratory (PNL).[5] The PNL wind data are first expressed in square kilometers of land, shown by electricity market region and by wind energy class. Wind energy values are grouped among seven wind-speed classes, with higher numbers indicating greater energy resources (Table 1). The few class 7 wind resources are included with class 6 (designated in Table 1 as "6+"), and winds below class 4 are generally regarded as not economically useful. Recognizing that some lands will not be made available for wind power use, EIA has adopted PNL's "moderate" wind resource exclusion scenario (Table 2).[6] Applying these criteria, EIA determines U.S. wind resources by region (Table 3).

As shown in Table 3, the United States has ample wind resources. Figure 1 shows the potential U.S. wind supply for wind power stations at different capital costs (excluding learning effects, improving capacity factors, and cost adjustment factors).[7] Although wind technologies are not comparable to baseload or other generating capacity, total U.S. wind resources equal about three times total U.S. generating capacity and could produce roughly twice the nation's current electric power generation, if costs were not an issue.[8] However, U.S. wind resources are heavily concentrated in a few regions (the NEMS electricity regions are shown in Figure 2). Nearly 60 percent of all U.S. wind resources are in the MAPP region, and no economically useful wind resources are recorded in FL and MAIN. Further, nearly 90 percent of U.S. wind resources are in the least valuable class, class 4. Thus, while plentiful overall, the best U.S. wind resources are not necessarily near either population concentrations or electricity demand centers.

Table 1. Wind Classes for Wind Energy Characterization

Average Annual Wind Speed (Miles per Hour)	Wind Class
Above 14.5	6+
13.4-14.5	5
12.4-13.4	4

Source: Pacific Northwest Laboratory, *An Assessment of Available Windy Land Area and Wind Energy Potential in the Contiguous United States*, PNL-7789 (August 1991).

Table 2. Percentages of Lands Excluded from Wind Energy Characterization in the Pacific Northwest Laboratory Moderate Exclusion Scenario

Land-Use Type	Percent of Land Excluded
Forest Land	50
Agricultural Land	30
Range	10
Mixed Agriculture/Range	20
Barren	10
Wetlands	100
Urban	100
Parks/Wilderness Areas.	100

Source: Pacific Northwest Laboratory, *An Assessment of Available Windy Land Area and Wind Energy Potential in the Contiguous United States*, PNL-7789 (August 1991).

The second step in the characterization limits usable wind energy resources to those sufficiently close to existing 115- to 230-kilovolt transmission lines. They fall within three distance zones (Table 4). All new generating capacity, regardless of technology type, has an associated standard transmission interconnection fee, which varies by region but averages about $225 per kilowatt. This fee represents the average cost of building a new line interconnecting the new generating plant with the existing network. In addition, extra costs averaging $5 per kilowatt per additional mile are added to account for the greater distance of wind sites from existing transmission networks (Table 4).

Finally, composite cost adjustment factors (Table 5) account for expected additional costs confronting actual

[5]Pacific Northwest Laboratory, *An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States*, PNL-7789 (August 1991), with updates, as available in National Renewable Energy Laboratory, *U.S. Wind Reserves Accessible to Transmission Lines*, draft for the Energy Information Administration (1994).

[6]PNL offers two levels of restriction, "moderate" and "severe." The severe restriction eliminates 100 percent of wind resources in each category.

[7]Figure 1 presents wind class effects in terms of capital costs. In the National Energy Modeling System (NEMS), large increases in wind resource use, along with passage of time, spur increased capacity factors and large learning effects, thereby markedly lowering capital and levelized electricity costs from wind power.

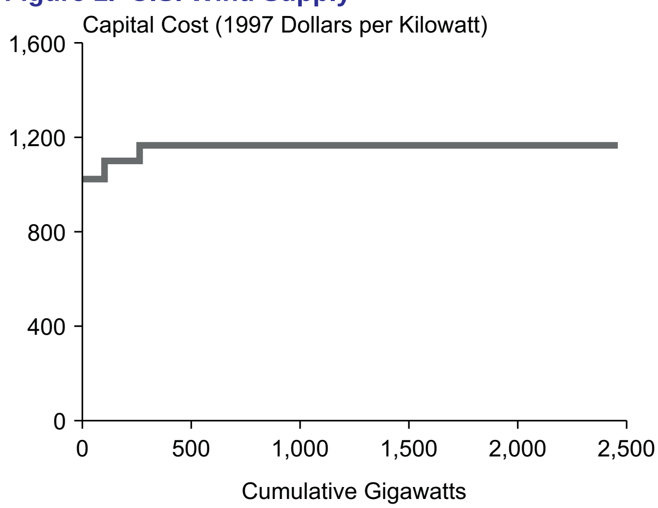
[8]Estimated at 32 percent capacity factor.

Table 3. U.S. Wind Resources for Electricity Generation, by Wind Class and NEMS Region
(Gigawatts)

NEMS Region	Gigawatts per Wind Class			
	6	5	4	Total
ECAR	0.0	0.4	3.5	**3.9**
ERCOT	0.0	0.0	9.9	**9.9**
MAAC	0.0	0.0	9.2	**9.2**
MAIN	0.0	0.0	0.0	**0.0**
MAPP	0.0	101.8	1,315.3	**1,417.1**
NY	0.0	0.3	3.1	**3.4**
NE	0.2	3.6	5.1	**8.9**
FL	0.0	0.0	0.0	**0.0**
STV	0.1	0.5	1.1	**1.8**
SPP	0.0	0.0	480.6	**480.6**
NWP	70.3	48.9	186.9	**306.1**
RA	23.2	1.4	174.1	**198.7**
CNV	8.0	4.4	7.7	**20.1**
Total	**101.7**	**161.3**	**2,196.6**	**2,459.6**

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 1. U.S. Wind Supply



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

U.S. wind development. All new wind generating capacity in every region is subject to one of five capital cost adjustment factors (steps). Capacity in the least-cost steps (steps 1 and 2) corresponds to the definition of economically accessible energy reserves. Capacity in steps 1 through 4 encompasses technically accessible resources (at current prices). All capacity (steps 1 through 5) encompasses the total wind resource base.[9]

The cost adjustment factors reapportion each region's total wind resources shown in Table 3. They allow an initial portion of regional wind resources to be built at no increase in capital costs, with increasing proportions constructed at capital cost increases of 20, 50, 100, and 200 percent above the base cost.[10] In the NWP region, for example, 7.7 gigawatts of wind resources are available at the base cost (itself affected by overall learning, capacity factor change, etc.), an additional 13.2 gigawatts are available at 20 percent above base cost, 8.6 gigawatts at 50 percent above, and 1.5 gigawatts at double the base cost. All remaining resources of the PNL allocation for NWP (275.2 gigawatts) are relegated to the most expensive step, step 5, with a 200-percent cost increase.

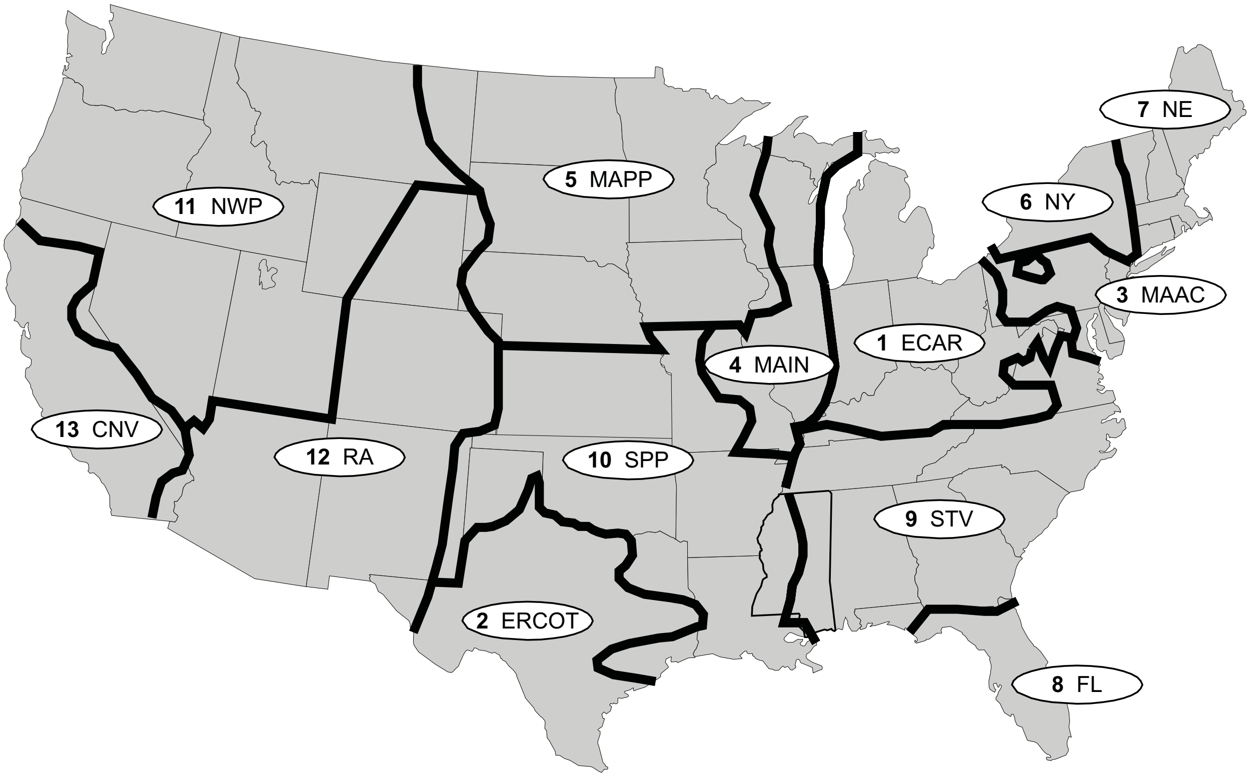
Learning-by-doing also affects wind technology capital costs. A region's resulting wind technology capital cost depends both on the overall nationwide increase in wind capacity, which lowers capital costs through learning-by-doing effects, and on the proportion of the region's wind resources already used, which increases costs of further penetration.

Cost adjustment factors are superimposed on the existing regional totals shown in Table 3. As a result, the cost-increasing effects of the cost adjustment factors are not evenly distributed within wind classes, but first apply to class 6 wind resources until either the resource or the weighted proportion is exhausted. Extending the NWP example, the subtotal of all 31 gigawatts of wind resources for the region, shown in steps 1-4 of Table 5, are obtained from the 70.3 gigawatts of class 6+ resources shown in Table 3.

[9]For additional definition and description of resource classes, see U.S. Department of Energy, Assistant Secretary for Conservation and Renewable Energy, *Characterization of U.S. Energy Resources and Reserves*, DOE/CE-0279 (Washington, DC, December 1989).

[10]Because NEMS employs a linear programming (LP) model, discrete steps are required rather than a continuous supply function.

Figure 2. Electricity Market Model Regions



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 4. Distance Zones, Miles From Wind Resources to Existing Transmission Lines

Zone	Distance (Miles)	Zone Width (Miles)	Average Additional Cost per Kilowatt (1997 Dollars)
1	0-5	10	12
2	5-10	20	35
3	10-20	40	70

Source: Office of Integrated Analysis and Forecasting, derived from Energy Information Administration, *Electric Trade in the United States 1992*, DOE/EIA-0531(92) (Washington, DC, September 1994), Table 42.

The effect of the cost adjustment factors is to redistribute available U.S. wind supplies. Figure 3 shows the redistribution at the National level. Figure 4—at a much reduced scale—shows the redistribution for the Northwest (NWP).[11] Clearly the effect of reallocation is to markedly reduce the quantities of wind available at all but the highest costs. Whereas wind supplies under class 6 designation alone (Table 3) offer nearly 102 gigawatts of least-cost wind supply, the effect of imposing cost adjustment factors is that only 28 gigawatts are in the least-cost step and 41 gigawatts in the next, together equaling only two-thirds of the best wind resources in the PNL-based allocation.

Basis for Wind Cost Adjustment Factors

Evidence From Experience

Separate from issues of turbine manufacturing cost, the supposition of plentiful U.S. wind supplies suggests relatively trouble-free siting of wind plants in the early years of commercial wind power development. However, actual U.S. plants proposed or entering service in the 1990s are confronting significant additional project costs, suggesting that unencumbered U.S. wind

[11]Figures 3 and 4 isolate wind class and cost adjustment factor effects separately from learning and other cost effects applied in NEMS. In NEMS, large increases in wind resource use, along with passage of time, also spur increased capacity factors and large learning effects, thereby markedly lowering capital and levelized electricity costs from wind power. EIA test runs utilizing step 5 ($3,000 per kilowatt) wind resources, for example, yield net wind capital costs under $2,000 per kilowatt when learning effects are included.

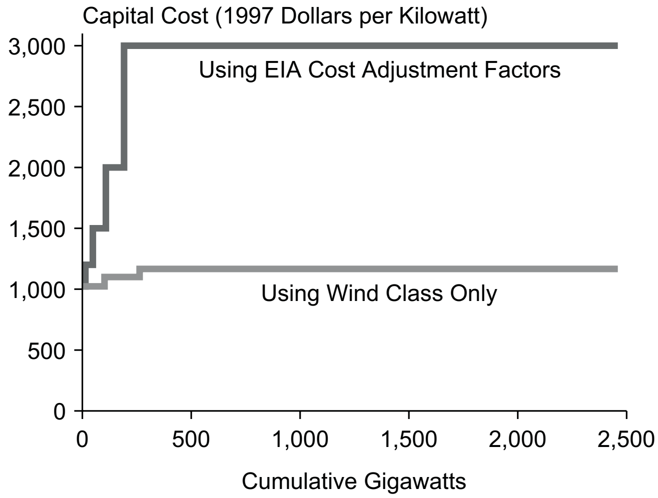
Table 5. U.S. Wind Resources by Region and Cost Adjustment Factor
(Gigawatts)

Region	Cost Adjustment Factor					
	Step 1 1.0	Step 2 1.2	Step 3 1.5	Step 4 2.0	Step 5 3.0	Total
ECAR	0.4	0.4	0.4	0.4	2.4	**3.9**
ERCOT	1.5	1.0	2.3	4.5	0.7	**9.9**
MAAC	0.9	0.9	0.9	0.9	5.5	**9.2**
MAPP	7.1	14.2	42.5	42.5	1,310.8	**1,417.1**
NY	0.3	0.3	0.7	0.7	1.4	**3.4**
NE	0.9	0.9	1.8	1.8	3.5	**8.9**
STV	0.2	0.2	0.4	0.4	0.7	**1.8**
SPP	2.4	4.8	14.4	14.4	444.5	**480.6**
NWP	7.7	13.2	8.6	1.5	275.2	**306.1**
RA	4.0	4.0	7.9	19.9	162.9	**198.7**
CNV	2.4	0.7	0.7	0.7	15.6	**20.1**
Total	**27.7**	**40.5**	**80.6**	**87.7**	**2,223.2**	**2,459.6**

Notes: EIA employs five discrete cost steps. Steps 1 and 2 represent two cost levels for wind reserves, either economically accessible now or in the very near future. Reserves plus higher cost steps 3 and 4 yield technically accessible resources, those which could reasonably become reserves by 2020. Step 5 represents that part of wind resources which EIA does not consider economically accessible by 2020 under any normal circumstances. Two regions, MAIN and FL, have no known economically useful wind resources. Totals may not equal sum of components due to independent rounding.

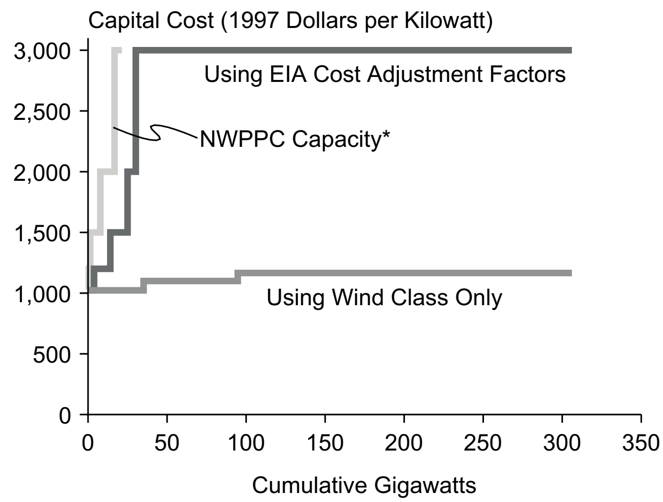
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 3. Comparing U.S. Wind Supply Estimates



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 4. Comparing Northwest Wind Supply Estimates



*Northwest Power Planning Council (NWPPC) values, converted to capital costs by EIA, were doubled to account for the larger NWP region represented in NEMS.

Sources: Energy Information Administration, Office of Integrated Analysis and Forecasting; and Northwest Power Planning Council, *Northwest Power in Transition: Opportunities and Risks*, Draft Fourth Northwest Conservation and Electric Power Plan (March 1996).

resources are not necessarily as plentiful as characterized in general cost estimates.[12]

First, natural phenomena can impose additional costs on new wind sites. Too strong or off-peak winds, storms, freezing, lightning, hail, vegetation, erosion, bird and animal habitat requirements, or other natural characteristics raise costs, reduce output, or reduce wind's market value. New wind plants in Minnesota, Iowa, Vermont, and Wyoming require reinforcement to cope with

[12]EIA treats these costs solely as capital costs. In fact, some, such as weather-related costs and maintenance of transmission and distribution links, also increase O&M costs. The result of incorporating these effects as capital rather than O&M costs is likely to understate their overall impact on wind technology costs.

winter storms and heating equipment to remove ice, which degrades performance and forces occasional shutdowns. Texas wind plants confront additional costs— both in original installation and in unanticipated replacements and repairs—from violent wind storms, tornadoes, hail, and lightning. In the West and Midwest, late winter and spring peak winds miss the summer electricity peaking demands. In the Northwest, winds tend to be unpredictable. Terrain slope and variation also raise costs and preclude developing large portions of otherwise attractive new wind sites in Minnesota and Wyoming. Steep, heavily vegetated, and difficult terrain eliminate many parts of New England and Northwest lands because of both higher installation costs for turbines, lines, roads, etc., and higher maintenance costs. Finally, coping with insects, birds, and local animals can raise costs or preclude current use of otherwise attractive wind areas. Insects coat Midwestern wind turbine blades, degrading performance and necessitating more frequent blade cleaning, thereby reducing output while increasing costs. Lessons learned from bird kills in 1980s California projects has accelerated 1990s avoidance of less expensive lattice towers, addition of special coatings and markings on turbines, measures to discourage nesting, and in some cases, avoidance of attractive windy areas used by migrating birds.

Second, although EIA accounts for costs of interconnecting new wind plants to the existing transmission network, the already loaded network is often unable to accommodate additional wind resources in important wind areas, thereby raising costs and reducing least-cost wind development opportunities. Northern States Power, ostensibly awash in wind resources relatively near transmission lines (Table 3), finds the existing in-state transmission network loaded and unable to accommodate more than 425 megawatts of wind capacity from the supposedly ample Buffalo Ridge wind area.[13] New wind projects in Wyoming and in Oregon faced significant cost hurdles in upgrades and power transmission charges. Major expansion of western wind power requires significant upgrades over a very long transmission corridor, and plentiful West Texas and panhandle winds face additional costs for wheeling power to major electric power markets in central Texas.

Finally, additional market preferences for alternative land use increase wind project costs and preclude otherwise excellent wind power projects, such as in Columbia Hills and Rattlesnake Hills (Washington), Burlington (Vermont), and Cape Cod (Massachusetts). In the West and Northwest, environmental, scenic, cultural, and religious values effectively restrict or preclude wind power development. Protection of birds, of Native American cultural and religious values, and of scenic vistas plays prominently in the elimination of seemingly excellent wind sites.

Lack of detailed information precludes separate representation of each additional cost in NEMS. However, observation of their effects on new U.S. wind plants—along with noticeably higher than expected capital costs—leads EIA to conclude that the additional factors need to be represented in the wind cost methodology. Literature reviews and contacts with industry professionals show that every large wind facility installed in the United States in the 1990s has been subject to at least some of the forces underlying the factors. Moreover, whereas EPRI-DOE estimates indicate that actual installed costs for new wind plants should average below $900 per kilowatt by 1999, costs for recent large installations appear to exceed $1,200 per kilowatt. For example, the 34-megawatt Big Spring project in Texas, reported at $40 million, averages $1,176 per kilowatt; a reported $235 million for the 193-megawatt wind facility at Alta, Iowa, yields an average cost of $1,220 per kilowatt; two new Northern Alternative Energy projects at Buffalo Ridge in Minnesota totaling 23.1 megawatts and $32 million average $1,380 per kilowatt; and the $60 million 41.4-megawatt Foote Creek Project in Wyoming yields a cost of $1,450 per kilowatt.[14] While these values may include some components not usually included in overnight capital cost definitions, EIA is not aware of any recent wind project completed at less than $1,000 per kilowatt.

Evidence From Regional Supply Evaluations

Three specific regional wind resource reviews—in Minnesota, California, and by the Northwest Power Planning Council (NWPPC)—indicate that economically accessible wind resources are less plentiful than indicated by wind speed and distance from transmission networks alone. The studies range from qualitative (Minnesota) to quantitative (California) to fairly detailed (NWPPC).

In 1996, Minnesota's "Appel Report" to the Minnesota Legislative Electric Task Force concluded with respect to wind resource areas that ". . . massive development of

[13]Energy Information Administration, Office of Integrated Analysis and Forecasting, derived from conversation with Northern States Power wind resources staff, February 16, 1999.

[14]For estimates of expected costs, Electric Power Research Institute and Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy, *Renewable Energy Technology Characterizations*, EPRI TR-109496 (Washington, DC, December 1997), pp. 6-13. For the Big Spring, Alta, and Foote Creek projects, Financial Times, *Renewable Energy Report* (March 1999), p. 4. For the Buffalo Ridge project, Energy Information Administration, Office of Integrated Analysis and Forecasting, derived from conversation with Northern Alternative Energy, June 18, 1999.

wind and biomass generation systems in Minnesota will require additions to the transmission system . . . [because] much of the renewable resource area lacks transmission capability . . . ."[15] The Appel Report—along with Northern States Power's difficulty in siting more than 425 megawatts—is the basis for sharply restricting least-cost wind supplies in MAPP and other similarly well-endowed wind resource regions.

The 1991 California Energy Commission (CEC) report, *Technical Potential of Alternative Technologies*, provides some quantitative information, essentially providing a technical upper bound of "reasonable" wind potential for that State.[16] While acknowledging a much larger PNL estimate of 37,000 megawatts as "gross technical potential," the CEC assessment of individual sites concludes that a reasonable technical potential for California is 4,460 megawatts under existing transmission constraints.[17] Loosening the transmission constraints somewhat increases the total technical potential to 5,385 megawatts.[18] In either case, the CEC estimates stand in sharp contrast to the 20.1 gigawatts shown in Table 3.

The 1996 NWPPC study, *Northwest Power in Transition*, provides one fairly detailed study relating wind technology costs and quantities.[19] The NWPPC study covers only the states of Idaho, Montana, Oregon, and Washington. Nevertheless, it provides a useful exposition of the general shape of a likely wind supply function. Figure 4 includes a representation of the NWPPC values (converted by EIA to capital costs), with NWPPC wind generating capacities doubled to account for the larger NWP region represented in NEMS.

The NWPPC wind supply function identifies 10,700 megawatts of potential wind power available in the four States at a range of costs below 20 cents per kilowatthour. Further, the report acknowledges that private developers have likely identified other cost-effective sites, and that still other sites probably exist, though they are likely small and best suited for local loads.

The NWPPC supply also illustrates limits to accessibility for wind power. Of the total 10,700 megawatts, NWPPC estimates that less than 2,000 megawatts could be developed at 6 cents per kilowatthour or less (1995 dollars) in the absence of a new transmission intertie to Montana. Moreover, the low costs would be achieved only if enough wind development occurred to distribute the high fixed costs of the necessary transmission upgrades. (Because of typically low capacity factors for wind projects, the cost of amortizing an increment of new transmission capacity is assigned to far fewer kilowatthours for a wind project than for typical fossil-fueled projects, again raising costs for wind-generated power.) Finally, although transmission remains the most important limiting factor, site viability is also limited by wind characteristics, topography, weather, environmental and habitat concerns, and land use conflicts.

The Minnesota, CEC, and NWPPC studies provide useful information for U.S. wind supply estimation. First, they begin to recognize economic constraints on some of the most important wind resources in the Nation. Second, they both quantify opportunities and identify general reasons for limitations in accessing wind resources. As such, they form a valuable base for EIA's representation of U.S. wind power. The three assessments have limitations, however, for wider application. The NWPPC study characterizes only part of the NEMS NWP region. Moreover, California and the Northwest—featuring great distances, large mountains, forests, and significant scenic, cultural, and environmental challenges—may not be representative of important Midwestern and Southwestern wind regions for which detailed information is not available.

Cost Adjustment Factors for U.S. Wind Supply

The five cost adjustment factors are broad applications of rates of cost increase and proportions of wind supplies derived from the Minnesota, CEC, and NWPPC wind resource information. In general, EIA makes the following assumptions:

- Regional estimates developed by EIA will not exceed estimates made by authoritative studies prepared by individual regions. Therefore, the CEC and NWPPC results set upper bounds on quantities and costs of economically accessible wind resources for those regions. EIA relaxes this assumption somewhat in the Northwest, to accommodate both NWPPC acknowledgment of additional "undiscovered" resources and adjustments for the larger NEMS region.
- There are fewer economically accessible winds (reserves) than technically accessible ones. The U.S. Department of Energy indicates that less than 1 percent of all technically accessible wind resources are

[15] Appel Consultants, *Evaluation of the Current Energy System in Minnesota*, Final Report (Valencia, CA, June 28, 1996), p. 23.
[16] California Energy Commission, *Technical Potential of Alternative Technologies*, Final Report, Contract 500-89-001 (Regional Economic Research, December 1991).
[17] California Energy Commission, page XIII-3.
[18] California Energy Commission, page XIII-2.
[19] Northwest Power Planning Council, *Northwest Power in Transition: Opportunities and Risks*, Draft Fourth Northwest Conservation and Electric Power Plan (March 1996).

economically accessible reserves, although technologies have improved since those estimates were made.[20] EIA takes into account that published wind resource estimates already exclude some land for economic reasons and assumes a much less severe reduction.

- Least-cost wind resources in every region are assumed to be sufficient to meet future wind capacity requirements in the EIA reference case.
- Wind resource distributions for small regions (those with fewer wind resources) are assumed to resemble the CEC distribution; wind distributions in large regions are assumed to resemble the distribution of the NWPPC study.

Examining Table 3 or Table 5 shows two broad regional groups, "small" wind regions with relatively few wind resources (less than 25,000 megawatts) and "large" wind regions with extensive wind resources (more than 175,000 megawatts). Given that CNV falls in the "small" category and NWP in the "large," EIA first established distributions for CNV and NWP and then broadly applied those distributions to other regions. As a result, ECAR, MAAC, NY, NE, and STV follow the CNV example, while MAPP, SPP, and RA follow the NWP distribution. Because its winds are considered generally accessible, ERCOT is treated as a special case of a small wind region, with higher proportions of its winds in lower cost categories.

EIA employs five discrete cost steps. Steps 1 and 2 represent two cost levels for wind reserves, either economically accessible now or in the very near future. Reserves plus higher cost steps 3 and 4 yield technically accessible resources, those which could reasonably become reserves by 2020. Step 5 represents that part of wind resources which EIA does not consider economically accessible by 2020 under any normal circumstances. The technical potential of 4,460 megawatts set by CEC, for example, becomes the control total for steps 1 through 4 in the EIA distribution.

EIA derives steps 2, 3, and 4 from two sources. First, to be useful, each of the cost steps needs to show meaningful cost increases; therefore, EIA chose each step to clearly differentiate major cost classes. Second, particularly for the initial steps, EIA very broadly applied cost breaks exhibited in the NWPPC supply. Finally, EIA chose the 200-percent increase (step 5) to separate resources determined extraordinarily unlikely to be economically accessible. All PNL wind resources in California and the Northwest in excess of the NWPPC and CEC estimates (as adjusted by EIA) are assigned the 200-percent increase; similar proportions are then applied to the PNL estimates for other regions.

Small Regions: Adapting CEC Information to ECAR, MAAC, NY, NE, and SERC

Using the CEC total as an approximate upper bound for California's technically accessible resources, EIA assigns 4,522 megawatts as the total of steps 1-4 and the remaining 15,585 megawatts to step 5. Of the 4, 522 megawatts, 1,710 megawatts representing already installed wind generating capacity are assigned to step 1 (reserves). In order to provide opportunities for least-cost growth and expansion in the other cost categories—but with no information available for the distribution—EIA allocates the remaining 2,812 megawatts equally across the 4 technically accessible resource steps. In effect, the CEC allocation places about 10 percent of wind resources in the lowest cost step and about 80 percent in step 5.

Other "small" wind resource regions are similar but not identical to CNV. The CNV allocation is unusual because of the large already-built component and the independently determined CEC bound. Therefore, for other small regions, a slightly lower proportion of total wind resources is assigned to step 1 and higher proportions are assigned to steps 2-4. Further, recognizing that U.S. Department of Energy and other energy resource characterizations show increasing resource proportions at higher costs, EIA generally increases the wind resource proportions for small regions as costs increase.[21] Finally, for all small regions except CNV, EIA increases the four lower cost step shares to offset the use of average rather than marginal costs (see below).

Large Regions: Adapting the NWPPC Estimates

Before applying the NWPPC results to other regions, EIA first adapts them to the larger NWP geographic region and then adjusts them to reflect the use of average cost steps rather than a continuous cost function. First, EIA doubled the NWPPC wind supply estimate for each supply step. The NWP region in NEMS is roughly twice the geographic size of the NWPPC region (Figure 2). Although the additional States in NWP (Nevada, Utah, and the western half of Wyoming) are less well endowed with wind resources than the NWPPC region, nevertheless, the NWPPC believes its region also contains additional undiscovered wind resources not included in its published wind supply. Therefore, to avoid underestimating total wind resources in the NWP region, EIA doubled the NWPPC wind supply estimates—from over 10,000 megawatts to nearly 21,000 megawatts—as an

[20]U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *Characterization of U.S. Energy Resources and Reserves*, DOE / CE-0279 (Washington, DC, December 1989).
[21]For example, see *Characterization of U.S. Energy Resources and Reserves*, pp. 19, 25, and 31.

estimate of all economically accessible wind in NWP steps 1-4.

Second, for both small and large wind resource regions, EIA increases the lower cost supplies to offset consequences of employing average costs in the defined steps. A drawback of step functions employing *average* costs is to overstate the *marginal* costs of the first units within each range. Overstating marginal costs for new technologies could have the effect of preventing initial purchases and thereby precluding the entire path of investment, learning, lower costs, and additional investment. To compensate for such overpricing, EIA reallocates portions of capacity from higher cost steps to lower cost ones, including some supply from step 5 into step 4, and thereby increases total wind supply in steps 1-4 to nearly 31,000 megawatts.

The effect of both EIA adjustments to NWPPC wind resources is to greatly increase lower cost wind supplies in NWP relative to the NWPPC estimates. Whereas NWPPC has less than 2,000 megawatts of least-cost wind supplies (including some winds in the Blackfoot Wind Resource area), EIA assigns 7,653 megawatts to step 1 for the NWP region. Whereas the NWPPC estimates yield less than 11,000 megawatts for *all* NWPPC wind resources, EIA includes nearly 21,000 megawatts for NWP reserves and nearly 31,000 megawatts for all NWP technically accessible resources in steps 1-4.

The NWPPC allocation is applied to the wind-rich MAPP, SPP, and RA regions, although steps 2-4 are assigned increasing quantities at higher costs to reflect the normal shape of supply functions. Step 1 is also reduced to reflect the scale of limitations on transmission access demonstrated by the Northern States Power experience at Buffalo Ridge. In effect, the NWPPC allocation places less than 3 percent of wind resources in the lowest cost step and more than 80 percent in step 5.

The ERCOT Special Case

ERCOT, covering major portions of Texas, is handled separately. The electrically integrated ERCOT region excludes most of the excellent winds in the western and panhandle areas of Texas. As a result, ERCOT becomes a small wind resource region, with less than 10,000 megawatts of wind resources in total. On the other hand, both ERCOT terrain and market conditions appear excellent for wind development. Therefore, EIA has assigned ERCOT a unique wind supply function offering moderate wind volumes at low costs (15 percent in step 1) and growing shares at intermediate higher costs, but with only 7 percent in the highest cost step 5.

Wind Projections

Recent EIA forecasts illustrate application of the wind cost adjustment factors. Table 6 shows EIA projections for U.S. wind generating capacity in 2020, by region, from the reference and high renewables cases of the *Annual Energy Outlook 1999* (*AEO99*) and in a case taken from *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity* (*Kyoto Protocol*).[22]

The cost adjustment factors have no effect on wind generating capacity builds in the reference case in *AEO99*. In most regions, wind capacity though 2020 remains well below the limits of step 1, the first level of reserves, especially in regions where wind development is most likely (the Midwest, most of the West, and Texas). California, also a likely wind development area, approaches first-step reserves limits by 2020.

The *AEO99* high renewables case, in which EIA assumes that renewable energy technologies have lower costs than in the reference case, illustrates the effect of the cost adjustment factors on wind penetration.[23] In this case the cost adjustment factors appear to have no effect on most regions, including the Midwest, Northwest, and ERCOT. However, in California (CNV) and in RA, wind capacity is projected to be built despite the 20 percent higher costs imposed by the cost adjustment factors. In California wind capacity growth stops at the end of defined reserves (step 2), indicating that the higher costs assumed for step 3 prevent additional wind capacity growth in the CNV region.

The *Kyoto Protocol* 1990-7% case, in which electricity producers choose large volumes of biomass and wind renewables in order to meet major U.S. carbon reduction requirements, can be seen as an “extreme” case. Results of the case show that the cost adjustment factors can have important effects in cases of high demand for renewables, both limiting wind power development and also contributing to higher electricity prices. Results suggest that very large increases in demand for wind power could exhaust economically accessible wind resources in some regions. Despite the technology cost reductions from expansion of wind power nationwide, resource constraints in some regions (ECAR, MAAC, and STV) result in installed wind costs approaching $1,800 per kilowatt by 2020. In California, all technically

[22]Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998), and *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF-98-03 (Washington, DC, October 1998).

[23]For more information on the high renewables case, see Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998), pp. 209 and 227, or *Assumptions to the Annual Energy Outlook 1999*, DOE/EIA-0554(98), pp. 68-70.

Table 6. U.S. Regional Wind Generating Capacity in Various Cases, 2020
(Gigawatts)

Region	Capacity Limit, Step 1	*AEO99* Reference Case	*AEO99* High Renewables Case	*Kyoto Protocol* 1990-7% Case
ECAR	0.4	0.0	0.3	2.2
ERCOT	1.5	0.2	1.2	4.3
MAAC	0.9	0.0	0.2	4.0
MAPP	7.1	0.7	0.8	7.0
NY	0.3	0.0[a]	0.2	0.7
NE	0.9	0.3	0.5	2.8
STV	0.2	0.1	0.4	1.6
SPP	2.4	0.0	0.8	10.1
NWP	7.7	0.0[a]	7.5	8.3
RA	4.0	0.2	7.1	5.6
CNV	2.4	2.1	3.1	5.0
U.S. Total	**27.7**	**3.6**	**22.0**	**51.4**

[a]Less than 0.05 gigawatt.

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

Sources: Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998), and *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity,* SR/OIAF-98-03 (Washington, DC, October 1998).

accessible resources (steps 1-4) are used and some step 5 resources are selected. In most regions, all least-cost reserves are exhausted. Nevertheless, even in this very demanding case, regions with large wind resources appear capable of complying without large cost increases. For such regions, the net result of learning effects and cost adjustment factors is to lower wind power costs.

Issues in EIA Wind Capital Cost Adjustment Factors

Given the limited information available, EIA's wind capital cost adjustment factors appear to yield plausible portrayals of increased costs with very large increases in wind power demand. However, they also have important limitations, particularly when analyses involve major growth of wind power. Although EIA is confident that installed costs increase as wind resources are consumed, there is considerable uncertainty about the *rate* of cost increases, the *extent* of cost increases, and *interregional differences* in wind technology costs. The most serious issue affecting the wind capital cost adjustment factors is the lack of basic data about the magnitude of wind technology cost change as wind resources are used. Lack of basic cost information challenges every stage of wind capacity forecasting, including both reference case projections with relatively small capacity increases and cases of high renewable energy demand. Much more information is needed on the components of wind technology cost increases, distinguishing natural resource issues from transmission and distribution and from market issues. Features and costs of transmission and distribution networks, for example, may be particularly important and may be usefully distinguishable from other forces.

Wind resource estimates for ERCOT and California are particularly problematic, especially because these regions are significant participants in wind energy markets. The challenge with ERCOT is in determining whether its vast wind supplies are really available in large quantities at constant costs, or whether and at what points limiting factors—such as transmission and distribution—exist. The challenge in California is in reconciling CEC resource estimates with amounts of already developed capacity, while retaining opportunities for additional wind power growth. EIA is working with analysts in both regions to determine improved factors.

EIA's current approach superimposes the cost adjustment factors onto the existing wind class and distance methodology in NEMS. In effect, EIA assumes that the best and closest winds are also those exempt from or least affected by natural resource, transmission access, and market forces. The higher costs are assigned to lower class, more distant, and less likely selected wind regimes. For example, in California, all 4.5 gigawatts in steps 1-4 (Table 5) are from the State's class 6 wind resource base (Table 3). In reality, the factors undoubtedly affect all wind classes at all distances. The result of this practice is to understate the costs of developing some portions of U.S. wind resources. EIA is considering measures to ameliorate these effects.

Conclusion

The issue of wind power opportunity is likely to become increasingly important in determining future U.S. electricity supply. Understanding wind prospects is important in expected “normal” energy futures as well as for possible exceptional ones. As wind turbine costs decline and their performance improves, the extent to which wind resources, transmission and distribution networks, and market forces complement or offset these improvements becomes all the more pertinent for near and mid-term electricity supply. If these additional factors have little influence, then improved wind technologies may enjoy fairly rapid penetration in normal U.S. electricity markets. To the extent that economically accessible wind resources are soon exhausted, networks are full, or markets are resistant, however, wind power may find itself still a marginal source of electric power supply.

Understanding actual wind prospects becomes all the more important in assessing proposed changes in national policy that could dramatically increase the demand for wind power. Relatively generous wind resource supplies could make policy choices that favor renewable energy technologies more attractive and less costly. Restricted wind resource supplies, in contrast, could portend much higher electricity prices, greater demands and impacts on consumers, and greater impacts on overall U.S. economic growth.

EIA’s use of wind cost adjustment factors formally recognizes the existence and importance of additional forces specific to wind technology in assessing U.S. wind energy supplies. Moreover, they appear to account in rough fashion for the scale of effects of such factors on U.S. wind power cost. Nevertheless, the importance of wind resource effects on overall U.S. electricity supply highlights the need for improved information about them.

Modeling Technology Learning in the National Energy Modeling System

by
Andy S. Kydes

This paper summarizes the approaches used to represent and treat technological progress and learning-by-doing in the National Energy Modeling System (NEMS). Because technologies and their adoption are represented somewhat differently in the various NEMS modules, based on the markets they represent, the treatment of technological learning in NEMS also differs by sector. Examples are given to illustrate the impact of learning on capital costs in recent policy analyses using the NEMS model.

Diffusion and Learning-by-Doing

Before they can provide widespread benefits, new technologies must pass through three phases: (1) invention—the development of a new technical idea; (2) innovation—the incorporation of the new idea into a commercial process for the first time, and (3) diffusion—the typically gradual process of adoption of the new product or process by potential users. Diffusion of technologies induces learning-by-doing for manufacturers and learning-by-using for consumers. These forces work in tandem in the market and are difficult, if not impossible, to separate. Learning relates cost reductions to cumulative capacity installed and is a surrogate for experience.

Because invention and innovation cannot be projected reliably, they are incorporated in the National Energy Modeling System (NEMS) through the technology menu made available to consumers over time. Independent expert engineering judgments are used to develop the technology menus. Subsequent cost and performance improvements (evolutionary changes) are a function of the diffusion and adoption of technologies in the market. The relationship between technology diffusion and learning—i.e., cost and performance improvements—in NEMS is the focus of this paper.

Background on Diffusion and Adoption

The paradox of the very gradual diffusion of apparently cost-effective energy-conserving technologies—why the technology diffusion process is gradual and what factors cause this to be the case—has been examined in recent studies.[1] The factors are grouped into (1) potential market failures, such as information problems, principal/agent slippage, and unobserved costs, and (2) non-market failures, such as private information costs, high discount rates, and heterogeneity among potential adopters. Two key adoption questions have been examined: what factors determine the rate of adoption of energy-conserving technologies, and what effects economic incentives and conventional regulations can have in encouraging technology adoption.

Research has consistently shown that diffusion of new, economically superior technologies is never instantaneous. Typically, it follows an "S-shaped" (sigmoid) curve, with the adoption rate initially slow, then faster, then slower as saturation is approached.[2] One commonly used model focuses on the spread of information regarding the existence and profitability of the innovation (the "epidemic model"). People are unlikely to use technologies they do not understand or are not aware of. If knowledge of existence and profitability are

[1]For example, see A.B. Jaffe and R.N. Stavins, "The Energy Paradox and the Diffusion of Conservation Technology," *Resource and Energy Economics*, Vol. 16 (1994), pp. 91-122.

[2]See Z. Griliches, "Hybrid Corn: An Exploration in the Economics of Technological Change," *Econometrica*, Vol. 25 (1957), pp. 501-522; S.W. Davies, "Inter-firm Diffusion of Process Innovations," *European Economic Review*, Vol. 12 (1979), pp. 299-317; S. Oster, "The Diffusion of Innovation Among Steel Firms: The Basic Oxygen Furnace." *Bell Journal of Economics*, Vol. 13 (1982), pp. 45-56; and S.G. Levin, S.L. Levin, and J.B. Meisel, "A Dynamic Analysis of the Adoption of New Technology: The Case of Optical Scanners," *Review of Economics and Statistics*, Vol. 69 (1987), pp. 12-17.

increasing functions of prevalence of use, then the use of a technology can be expected to spread like a disease: the probability that a non-user will adopt the technology in any time period will be an increasing function of the fraction of the population that has already adopted (been infected). The formulation can be characterized as follows:

$$dS_t / dt = a(C, P, ...) [S_t / U_t] * [1 - S_t / U_t] \quad ,$$

where

S_t = the stock of users who have adopted the technology by time t,

U_t = the universe of potential users of the technology by time t, and

$a(C, P, ...)$ = the infectiousness of the disease (technology)—a parameter that depends on fuel prices (P), equipment costs (C), and possibly other factors.

Notice that $[S_t / U_t]$ is the probability of encountering an "infected" person and contracting the disease (adopting). The second factor, $[1 - S_t / U_t]$, is the proportion of the population that is "healthy," representing candidates for "infection" (adoption).

Although a was specified as a constant in the original contagion formulation, Griliches established that diffusion is a function of economic returns to adoption. Mansfield showed that the rate of diffusion can depend on the size of the adopting firms, the perceived riskiness of the new technology, and the absolute size of the required investment.[3] In such models, even if a technology is profitable for all firms, diffusion is gradual because it takes time for all firms to be "exposed."

David proposed that potential adopters are heterogeneous in their evaluation of cost-effectiveness, that is, they have a distribution of hurdle rates.[4] Early adopters have the lowest hurdle rate and, by making early purchases of a new technology, enable a portion of the market to "learn" about the technology (learning-by-using) and manufacturers to reduce their production costs (learning-by-doing). The new cost reductions can then make the technology economical for an additional portion of the market, and the process is repeated until the market share stabilizes.

Market Barriers

Factors that slow the adoption of apparently superior technologies in the market are referred to as "market barriers." Barriers that keep a market from behaving efficiently are termed "market failures." Other barriers are not failures, because they typically reflect hard-to-quantify costs that are incorporated by the market to develop an efficient equilibrium.

The following barriers are market failures:

- *Societal lack of information about technologies/practices*. There are private and societal aspects to information. At the societal/market level, a well-working, efficient market is characterized by perfect (or near-perfect) information flow. To the extent that public information is not communicated efficiently, the market is imperfect and could represent a market failure. Government information programs, such as those developed by the U.S. Environmental Protection Agency to educate industry and builders on best practices, are aimed at overcoming some of these failures.

- *Principal/agent problem*. In some cases, the party who makes the purchase is not the one who pays the bills for the use of the technology. For example, if the builder of a new house cannot credibly represent its energy efficiency to the potential buyer, then the sale price may not reflect the efficiency attributes. Similarly, a landlord may not be able to recover all of the value of the energy efficiency investments when renters pay the fuel bills. People living in nursing homes (or apartments) where utility costs are included in the rent may not see any incentives to conserve. Low-income families living in homes where the energy bill is subsidized by a government, utility, or nonprofit agency may not have any incentive to conserve energy.

- *Distorted prices*. Consumers may face subsidized or invariant pricing, which does not foster energy conservation. Average pricing instead of marginal cost pricing for natural gas and electricity is one example where prices are artificially low and conceal the true cost of new energy supplies. Uninternalized environmental externality costs from fossil energy, nuclear and hydroelectric, or other renewables represent possible sources of artificially low prices. Subsidies are another example.

[3]E. Mansfield, *Industrial Research and Technological Innovation* (New York, NY: W.W. Norton, 1968).

[4]P.A. David, *A Contribution to the Theory of Diffusion*, Stanford Center for Research in Economic Growth, Memorandum 71 (Stanford, CA: Stanford University, 1969).

The following market barriers are not market failures:

- *The cost of acquiring private information can be high*. It costs something to learn about a new device or appliance and how a technological improvement fits into one's home or firm. There may also be greater costs in learning about reliability of suppliers of new technologies than in learning about the reliability of suppliers for previously existing technologies. The purchase price of a new product is a lower bound to the true cost.

- *Implicit discount rates can be high*. Sutherland notes that high discount rates may be appropriate because investments are irreversible, with much uncertainty about payback—both because future energy prices are uncertain and because actual life-cycle savings in any particular application can only be estimated.[5]

- *The market is heterogeneous*. A given technology could be profitable on average but not for everyone. If the population is heterogeneous in the amount of energy it uses, for example, a technology that is profitable for the average user may not be attractive for some portion of the population. The engineering cost-effectiveness calculation estimates the profitability for the mean household or firm.

- *The wait-and-see phenomenon in retrofit cases may delay adoption*. For example, if product costs are continuously falling (like the price of desktop computers), a consumer may save more by waiting for prices to reach a given level later than could be saved on operating costs with a current purchase. That is, it can pay to wait, despite the fact that the current net benefits of adoption are positive.

Non-market failures typically represent internalized costs (barriers) that are used by a well-working, efficient economy to allocate resources optimally. Such barriers help to explain why the diffusion of energy conservation technologies is gradual. Government intervention to offset such barriers may decrease the efficiency of the market without providing compensating gains, and thus is not necessarily warranted.

Learning-by-Doing

Although innovation (technical progress) and learning-by-doing may appear to be synonymous in this paper, they are not. However, they are related. Technical progress or innovation is commonly understood to mean the introduction of a new product or service into the market. Such products often, but not always, have greater efficiency *and* greater equipment cost than the alternatives for providing the same service. The cost per unit of output can be higher or lower for the new technology when both equipment and fuel costs are considered. For example, a SEER 18 central air conditioner costs about $900 more than a SEER 10 central air conditioner but is 80 percent more efficient. The total annual electricity cost savings from using a SEER 18 central air conditioner at today's national average electricity price is about $110 per year. Thus, it would take roughly 8 years to recover the difference in equipment costs.

An 8-year payback period has traditionally been unacceptable for U.S. residential or commercial investments, and very few 18 SEER units are sold. Consequently, although the SEER 18 central air conditioner unit represents a significant technical advance, the overall efficiency in residential/commercial cooling is not improved *solely* by the availability of the advanced SEER 18 technical achievement because of its negligible market adoption.

In the context of this paper, we refer to technological progress as the combination of technical progress, adoption, and learning-by-doing. Because considerable technical progress, resulting in either cost reductions or efficiency improvements for existing technologies, occurs through adoption-stimulated manufacturing production experience (as well as research and development), learning is tied to both adoption and innovation. Technological progress in this paper measures the *net technology impact* on the market—that is, the combination of innovation, adoption of the more efficient technologies in the market, and learning (cost reductions and efficiency improvements induced by either manufacturing or consumer experience).

[5] R. Sutherland, "Market Barriers to Energy Efficiency Investments," *Energy Journal*, Vol. 12, No. 3 (1991), pp. 15-34.

Returns to adoption (another expression for learning-by-doing) are cost reductions due to manufacturing efficiencies and experience—usually taken as a function of cumulative capacity or the number of units built.[6] Wright, for example, noted that the direct labor costs of manufacturing airframes declined by 20 percent for every doubling of cumulative capacity.[7] Other authors have subsequently broadened the analysis of learning to other costs and shown that they also declined with experience. More recently, Hatch and Mowery have tied learning (in the semiconductor industry) to cumulative engineering resources devoted to implementing a new process on the manufacturing production line, not just cumulative production.[8]

Findings of recent studies indicate the following. There is always some loss of learning when a technology is transferred from research and development to the manufacturing production line. Global competition promotes global information and learning-by-doing (that is, production is local but learning is global). The more standardized (“commoditized”) a product is (like paper clips, radios, and gas turbines), the more likely it is that the product cycle time will be condensed and the more rapidly the learning-by-doing will occur.[9] The more mature a technology, the more likely it is that learning will diffuse into the marketplace, because experts have time to move between firms. And finally, at the technological frontier, learning is limited to a small group of individuals or firms and disseminates more slowly to competing firms.[10]

Technology Representations in NEMS

The National Energy Modeling System (NEMS)[11] was developed by the Energy Information Administration (EIA) in 1993. NEMS is a large, regional, modularly designed, technology-rich, energy-economy model that solves for an annual equilibrium in U.S. energy markets. It is particularly well suited to address policy issues focusing on technological change.

Technological decisionmaking in NEMS is tailored to the sector being modeled (e.g., utilities minimize costs subject to environmental constraints, whereas for residential markets cost is only one of a number of criteria used to choose appliances). Six of the major modules in NEMS (residential, commercial, transportation, refineries, electricity, and natural gas transmission and distribution) characterize technologies explicitly in the engineering sense, that is, with thermodynamic efficiency, specific fuel inputs and outputs, maximum capacity factors, unit capital costs, operations and maintenance (O&M) costs, physical lifetime, first year of commercial availability and installation, and maturity status (vintaged capital stock). The remaining NEMS modules (coal, oil, and gas production and industrial energy demand) represent technologies implicitly in the sense that technological change is embedded in other trend parameters that have been derived either through econometric methods or through engineering

[6]Learning-by-doing has been well documented since the 1930s for a wide variety of industries. For example, learning-by-doing has been documented for airframes, automobile assembly, chemical engineering, clerical activities, housing construction, machine tools, metal products, nuclear plant construction, petroleum refining, printing and typesetting, radar, rayon, and semiconductors. See T. Wright, “Factors Affecting the Cost of Airplanes,” *Journal of Aeronautical Science*, Vol. 3, No. 4 (1936), pp. 122-128; A. Alchian, “Reliability of Progress Curves in Airframe Production,” *Econometrica*, Vol. 31 (1963), pp. 679-693; N. Baloff, “Extension of the Learning Curve,” *Operations Research Quarterly*, Vol. 22 (1971), pp. 329-340; M. Lieberman, “The Learning Curve and Pricing in the Chemical Processing Industries,” *RAND Journal of Economics*, Vol. 15, No. 2 (1984), pp. 213-228; M. Kilbridge, “A Model for Industrial Learning,” *Management Science*, Vol. 8 (1962); J. Dejong, “The Effects of Increasing Skill on Cycle Time and Its Consequences for Time Standards,” *Ergonomics*, Vol. 1, No. 1 (1958), pp. 51-60; W.Z. Hirsch, “Process Functions of Machine Tool Manufacturing,” *Econometrica*, Vol. 20, No. 1 (1952), pp. 81-82; L. Dudley, “Learning and Productivity Changes in Metal Products,” *American Economic Review*, Vol. 62 (1972), pp. 662-669; R. Cantor and J. Hewlett, “The Economics of Nuclear Power: Further Evidence of Learning, Economies of Scale, and Regulatory Effects,” *Resources and Energy*, Vol. 10 (1988); W.B. Hirschmann, “Profits from the Learning Curve,” *Harvard Business Review*, Vol. 42, No. 1 (1964), pp. 125-139; F. Levy, “Adaptation in the Production Process,” *Management Science*}plain , Vol. 11 (1965), pp. B136-B154; L. Preston and E. Keachie, “Cost Functions and Progress Functions: An Integration.” *American Economic Review*, Vol. 54, No. 2 (1964), pp. 100-107; R.S. Jarmin, “Learning by Doing and Competition in the Early Rayon Industry,” *RAND Journal of Economics*, Vol. 25, No. 3 (1994), pp. 441-454; D. Webbinick, *The Semiconductor Industry: A Survey of Structure, Conduct and Performance*. Staff report to the Federal Trade Commission (Washington, DC: U.S. Government Printing Office, 1972); A.R. Dick, “Learning by Doing and Dumping in the Semi-conductor Industry,” *Journal of Law Economics*, Vol. 34 (1991), pp. 134-159; D.A. Irwin and P.J. Klenow, “Learning by Doing Spillovers in the Semiconductor Industry,” *Journal of Political Economy*, Vol. 102, No. 6 (1994), pp. 1200-1227; and N.W. Hatch and D.C. Mowery, “Process Innovation and Learning by Doing in Semiconductor Manufacturing,” *Management Science*, Vol. 44, No. 11 (November 1998).

[7]T. Wright, “Factors Affecting the Cost of Airplanes,” *Journal of Aeronautical Science*, Vol. 3, No. 4 (1936), pp. 122-128.

[8]N.W. Hatch and D.C. Mowery, “Process Innovation and Learning by Doing in Semiconductor Manufacturing,” *Management Science*, Vol. 44, No. 11 (November 1998).

[9]A.R. Alvarez, “Process Requirements Through 2001,” presented at the Second International Rapid Thermal Processing Conference (1994).

[10]N.W. Hatch and D.C. Mowery, “Process Innovation and Learning by Doing in Semiconductor Manufacturing,” *Management Science*, Vol. 44, No. 11 (November 1998).

[11]See Energy Information Administration, *The National Energy Modeling System: An Overview*, DOE/EIA-0581(98) (Washington, DC, February 1998). The Appendix to this paper provides a brief overview.

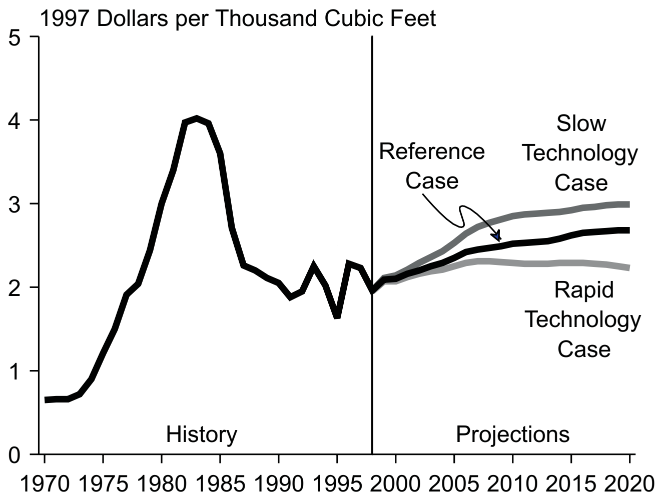
judgments. Learning-by-doing has been modeled in three ways in NEMS.

Learning-By-Doing in the Oil and Gas Supply Module

For the implicitly defined modules, such as the oil and gas module, time-dependent rates of change of key parameters that ultimately determine the cost of bringing new reserves into play are defined by improvements in such factors as cost per well, success rate, and the rate of increase of inferred reserves. Whenever technologies are represented implicitly in NEMS, learning-by-doing, innovation, and market penetration of advanced technologies are merged into one concept, which for simplicity we call "technological progress." Horizontal drilling, improvements in reinjection technology, and improved computer applications (to interpret seismic data) are relatively recent technological innovations (technical progress) that have combined with increasing use (learning-by-using) and decreasing costs (learning-by-doing) to prompt further adoption and cost reductions.

Net rates of improvement typically are estimated econometrically or derived through expert engineering judgement. The sensitivity of the solution is investigated and reported periodically in the *Annual Energy Outlook*. Below is one example of how the wellhead price of natural gas might change with a change of one standard deviation in the technological progress parameters. Shown in Figure 1 is the impact of slow and rapid technological progress cases, run both in standalone mode (without any interaction on demand) and integrated with full market responses to price changes. The impacts of the technological change implied by a difference of only one standard deviation are significant.

Figure 1. Lower 48 Natural Gas Wellhead Prices in Three Cases, 1970-2020



Source: Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998), Figure 98, p. 74.

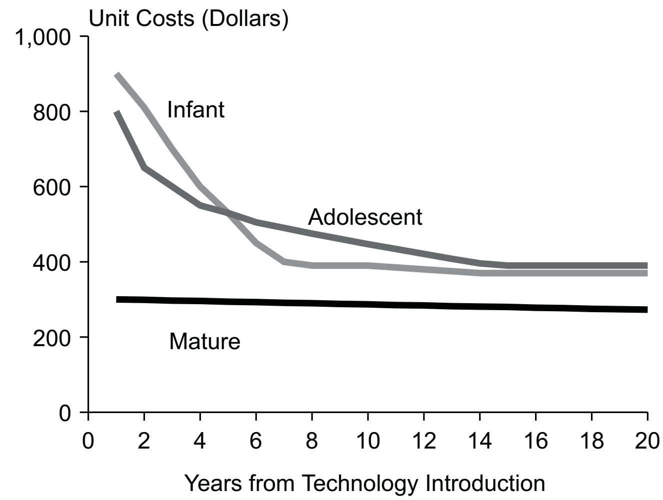
Technological Learning in the Residential, Commercial, and Transportation Modules

In the NEMS building and transportation sectors, equipment choices are based on logit (or nested logit) models that can be derived from variations of the epidemic model described earlier. The production of end-use energy appliances tends to be standardized, and although the product cycles are typically longer than those associated with memory chips for computers, technological learning is short enough and investment small enough for learning to be characterized as a function of time instead of cumulative production experience (given stable fuel prices with some year-to-year perturbations).

Technologies in the buildings sector can be classified as either mature, adolescent, or infant. Each classification identifies the rate of cost reductions or efficiency improvements that can occur over time. For mature or costly new technologies, the cost declines or efficiency improvements are either constant or slightly declining. The costs for adolescent technologies are gradually declining, because some adoption has occurred as a result of the heterogeneity of consumers, and their preferences result in additional cost or performance improvements. For infant but cost-effective technologies, the initial technology cost is low enough for significant early adoption and learning to take place, further reducing costs. The three options are illustrated in Figure 2. Figure 3 illustrates the actual projected cost declines for compact fluorescents, an adolescent technology in commercial lighting.

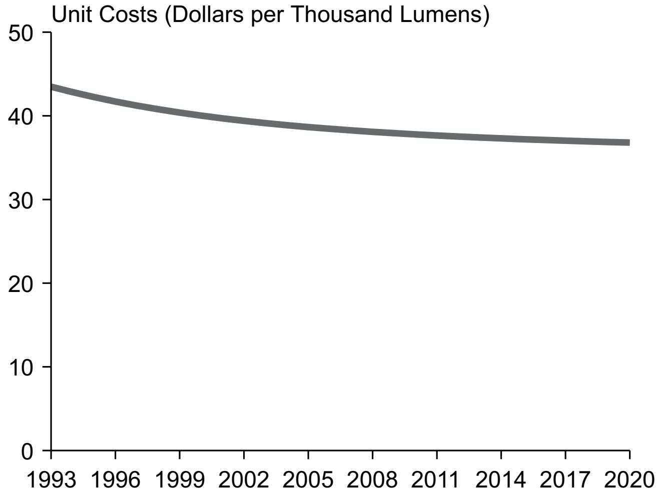
Sources for the exogenous estimate of how much technological learning can take place in the buildings sector

Figure 2. Example of Learning: Buildings Sector Technologies



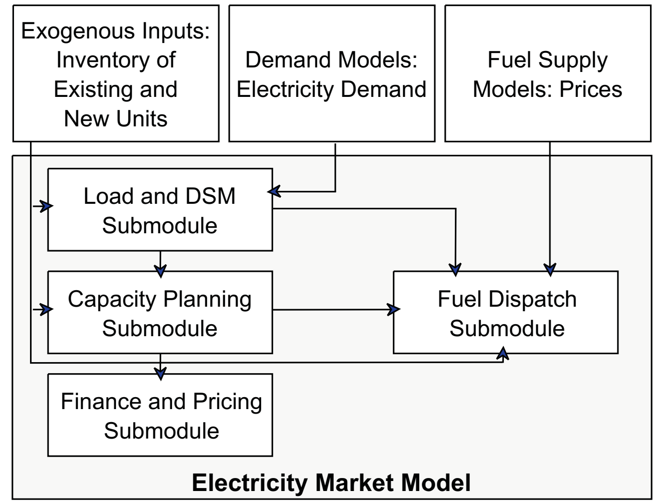
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 3. Capital Costs for Compact Fluorescent Lighting in the *AEO98* Reference Case



Source: Energy Information Administration, *Assumptions to the Annual Energy Outlook 1998*, DOE/EIA-0554(98) (Washington, DC, December 1997).

Figure 4. Overview of the NEMS Electricity Market Module (EMM)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

are based on engineering and market penetration estimates by A.D. Little.[12] Exogenous estimates for technological learning in the transportation sector are based on work by Energy and Environmental Analysis, Inc., and others under contract to the U.S. Department of Energy. Two sets of time-dependent learning assumptions usually are provided. One set, for the reference case, assumes that the current market conditions will prevail into the future (reference case assumptions). Another set of cost and performance characteristics for advanced technologies is also developed by A.D. Little and assumes that additional sales will be generated through industry and government actions (possibly, increased research and development) that accelerate learning (the rapid technology case). Cost reductions through manufacturer learning associated with each market scenario are developed exogenously and translated to scenario-dependent and time-dependent paths of cost reductions.

Learning in the Electricity Market Module

The NEMS Electricity Market Module (EMM) is a large regional model of the U.S. generation market. The United States is divided into 13 NERC (National Electricity Reliability Council) regions or subregions, and each region is treated as a large single utility that optimally adds capacity and dispatches and prices electricity subject to market conditions (competitive or regulated) and environmental constraints for sulfur and nitrogen oxides (NO_x) (Figure 4).

Currently, 5 of the 13 regions are assumed to be competitive and use marginal-cost pricing for generation (California, New York, New England, Mid-Atlantic Area Council, and Mid-America Interconnected Network). Those 5 regions have instituted legislation toward market pricing. The 8 other regions are assumed to continue with cost-of-service pricing in the reference case. Key regional inputs to the EMM include end-use electricity demand and associated load profiles, delivered fuel prices and availability, the current and future menu and cost and performance characteristics (efficiency, maximum capacity factor, capital and O&M costs, etc.) of available generation units with their date of initial installation, the risk factor associated with investments in new capacity, degree of maturity, environmental and fuel-use regulations, and the degree of market structure.

Some of the key features of the EMM follow. Capacity expansion planning using a multi-year horizon is formulated as a dynamic linear program to optimally dispatch current and future technologies to minimize costs across all time slices. The solution is adjusted to reallocate a portion of the new generation capacity to those technologies that were marginally unattractive, to account for the heterogeneity of electric utilities within a region. Annual electricity demand is divided into 27 time segments per year for planning purposes, and demand for dispatch is divided into 108 time segments. Local and Federal environmental regulations are treated endogenously. Traditional cogeneration (combined heat

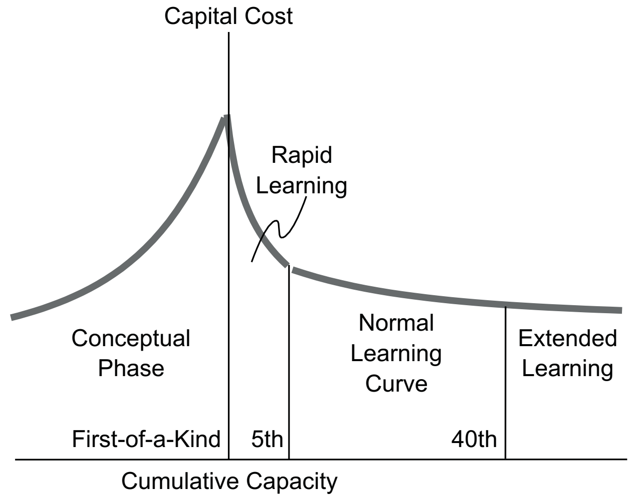
[12] A.D. Little, Inc., *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Reference Case*, No. 37125-00 (Washington, DC, September 1998); A.D. Little, Inc., *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case*, No. 37125-00 (Washington, DC, September 1998).

and power systems primarily for own use) is represented in the demand sectors (industrial and commercial), refinery sector, and the oil and gas supply sector. Twenty-six technologies are explicitly represented: 15 fossil-fueled, 1 nuclear, and 10 renewable. Most importantly, technology costs are adjusted to reflect learning with market penetration—learning-by-doing—as described below. Important additional features of the utility capacity expansion module include an adjustment for technological optimism,[13] the adjustment of discount rates for risk and uncertainty, the use of "reduced costs" to reallocate some of the planned capacity to technologies that are almost competitive, and the use of either adaptive[14] or rational[15] expectations.

Technological optimism is defined as the difference between initial engineering estimates and final first-of-a-kind costs. New technology costs are uncertain because all components are not known with certainty. Some designs may be novel or untested for large-scale plants. Initial capital costs tend to be underestimated. As more of the engineering design becomes definitive, costs become more certain and tend to increase. First commercial plants tend to be manufactured inefficiently and to require design modifications and adjustments. After the first few units, normal learning takes place and costs decline at a more gradual pace (Figure 5). Learning-by-doing is the process by which the market gains operational and manufacturing experience.

In NEMS, the cumulative capacity or number of full-sized plants constructed is used as a surrogate for experience. The use of this modeling feature allows for the analysis of market "lock-out"and "lock-in." Preventing the lock-out of new technologies that have high (uncompetitive) initial costs but are expected to have much lower costs after learning-by-doing occurs is the goal of technology deployment programs. This modeling feature allows the simulation of policies that affect technologies in the early stages of commercialization and represents the effects of learning on cost reduction.

Figure 5. Technological Learning



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Electricity Technology Adjustment and Characterization

The basic steps in the adjustment algorithm (Figure 6) are as follows:

- Input the cost and performance characteristics for both inherited and new technologies, including level of maturity (cumulative builds to date), optimism factors, and learning rates. For new technologies, the mature technology cost is input, and the model adjusts the cost downward on the basis of cumulative capacity built. In some instances, such as wind and biomass generation, total installed costs can rise above the learning-induced capital costs in the short term when capacity expansion occurs too rapidly for the industry to accommodate. See the paper on "Modeling the Costs of U.S. Wind Supply" in this publication for an expanded discussion.
- Adjust the discount rate used for each technology by the risk factor. The risk factor is based on the size of the investment and construction lead time and is estimated by EIA on the basis of work by Pindyck.[16]
- Adjust the overnight capital costs for the optimism factor and learning factor, depending on its cumulative capacity and which learning phase the technology is in. During the early learning phase (units 1-5), the major manufacturing inefficiencies and component redesigns are eliminated, and the learning rate is at its highest (Figure 5). During the normal learning phase (units 6-40), learning continues at a more modest rate and reflects the behavior of adolescent technologies. During the mature learning phase (units 41 and beyond), learning is assumed to occur very slowly (Figure 5).

[13]E.W. Merrow, K.E. Phillips, and C.W. Myers, *Understanding Cost Growth and Performance Shortfalls in Pioneer Process Plants* (Santa Monica, CA: The RAND Corporation, 1981).

[14]Adaptive expectations estimates future prices or quantities based on recent trends. These could be, for example, an extrapolation of the previous 5 years' rates of change.

[15]Rational expectations means that the module uses all the information available to the model about the past, present, and future. For dynamic optimization models, rational expectations means "perfect foresight." For NEMS, this means expectations about the future based on a previous NEMS solution of a similar scenario.

[16]R.S. Pindyck, "Investments of Uncertain Costs," *Journal of Financial Economics*, Vol. 34 (1993), pp. 53-76.

- Develop price and electricity demand expectations. The expectations can be based on rational expectations, based on information from a previous model run, or based on a recent trend (adaptive expectations).

- Select the optimal capacity mix. Price and demand expectations, combined with risk, learning-adjusted capital and fixed O&M rates, and efficiencies, are used for the selection of capacity types.

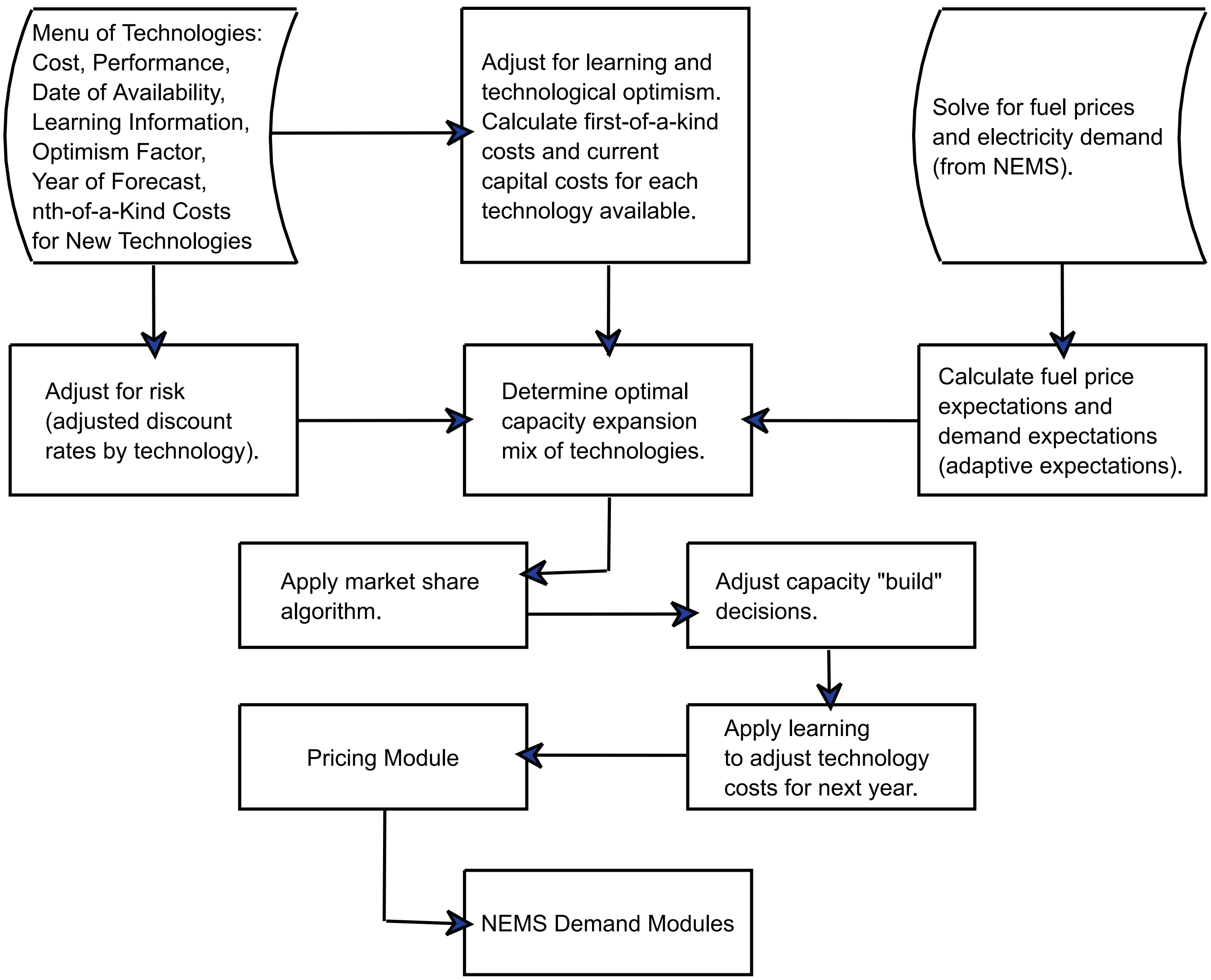
- Readjust the shares of new capacity for heterogeneity of utilities according to the market adjustment algorithm. All utilities in a region do not have the same cost structure or equal access to the same fuels, as discussed below.

- Finally, adjust capital costs for learning, based on the new projected construction.

Learning Curves in the EMM

Learning-by-doing, as shown in Figure 5, is characterized in three piecewise nonlinear curves for overnight costs:[17] early rapid learning (units 1-5), normal learning (units 6-40), and extended learning (units 41 and beyond). The standard capacity of a unit is a function of the technology. For example, the standard size for a fuel cell is 10 megawatts, and the standard size for a gas combined-cycle unit is 400 megawatts (see Table 1). Overnight costs are a function of cumulative capacity, where capacity is measured in numbers of standard-sized units. The functional form[18] has the nonlinear form:

Figure 6. Electricity Technology Adjustment and Characterization



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

[17] Overnight costs, the capital costs of a plant if the plant were built and paid for overnight, are sometimes known as specific costs. For example, if the capital cost of a plant is $600 per kilowatt and 400 megawatts were built overnight, then the “overnight cost” would be $240 million.

[18] D.F. Abell and J.S. Hammond, *Strategic Planning: Problems and Analytical Approaches* (Englewood Cliffs, NJ: Prentice-Hall, 1979).

$$OC(C) = a * C^{-b} \quad ,$$

where C is the cumulative capacity in numbers of standard-sized units.

The progress ratio (*pr*) is defined by speed of learning (e.g., how much costs decline for every doubling of capacity). In NEMS, the percentage reduction in capital cost for every doubling of cumulative capacity (f) is an exogenous parameter input for each technology. Consequently, the progress ratio and the NEMS input f are related by

$$pr = 2^{-b} = (1 - f) \quad .$$

We can solve for b in terms of f. Once b is solved, a can be found from initial conditions. Thus, once the rates of learning (f) are known for each interval, the corresponding parameters (a and b) of the nonlinear function are known. The overnight costs can be computed for any amount of experience (cumulative number of units built).

The Market Adjustment Algorithm

Technologies in the EMM are defined as "competitive" when the annualized cost of the capital plus operating and maintenance costs of a technology are low enough to be adopted in the optimal capacity expansion planning decision. For example, on a cost per kilowatthour basis, gas combined-cycle plants in the 2000-2010 time frame typically are expected to cost about $0.04 per kilowatthour, are competitive, and are selected in the planning process; solar photovoltaic systems typically are expected to cost more than $0.25 per kilowatthour, are not competitive, and are not selected in the planning process. The recalculation of market shares after the Capacity Expansion Model has solved for the optimal expansion plan is designed to account for heterogeneity of utilities within the NERC regions. The recalculation of market shares is based on the levelized fixed costs (capital plus fixed O&M) of the selected new generation capacity and the costs of the marginally uncompetitive technologies. The fixed costs of each technology are checked to determine whether they were within 20 percent of being competitive. For those technologies that are within 20 percent of being competitive, each market share is reallocated according to a logit function. More precisely, we define

F_i = the levelized costs of capital cost plus fixed O&M for technology i, and

R_i = the "reduced cost" for technology i in the optimal solution.

The solution to a linear programming model produces "reduced costs" for every variable in the optimal solution. The reduced cost represents how much the cost of that technology must be reduced to become economically attractive. The reduced cost for a "basic" variable in a linear programming formulation, a technology that was selected by the program, will be zero in the NEMS formulation. Those that were not selected will be positive. Next we compute the following ratio for each technology and check to see whether it is less than or equal to 1.2.

$$Ratio_i = F_i \,/\, |(F_i - R_i)| \quad ,$$

where we check to be sure that $|F_i - R_i| > 0$ (i.e., the absolute value of the difference, $F_i - R_i$, is greater than zero).

For all technologies that satisfy the condition that costs are within 20 percent of being competitive ($ratio_i \leq 1.2$), we allocate new capacity shares according to the following logit function:

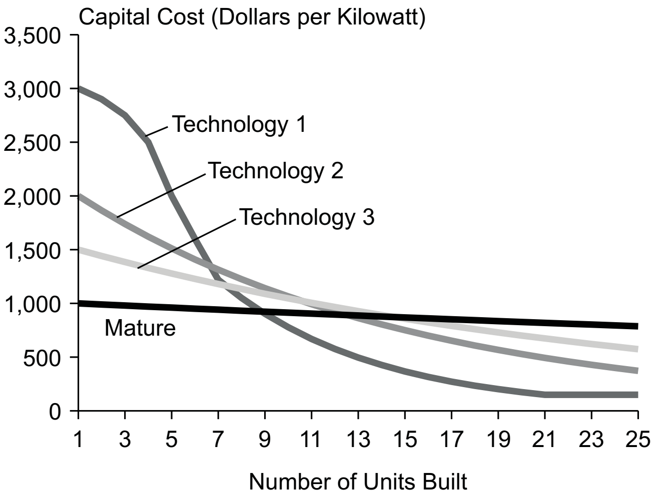
$$S_i = (ratio_i)^{-\gamma} \,/\, \left(\sum_{j=1}^{n} (ratio_j)^{-\gamma}\right) \quad .$$

The larger the exponent γ is in the logit formulation, the more the region resembles a homogeneous single utility that optimizes capacity expansion plans. The choice of γ=11 as an exponent means that a relatively small share of new capacity will be given to marginally uncompetitive technologies with fixed annualized costs approaching 20 percent above the current market. $Ratio_i$ could have been calculated on the basis of both annualized fixed costs plus variable O&M and fuels costs; however, such a calculation would have added significant complexity (and more assumptions) to the computation, because the variable costs are a function of the actual generation, which are unknown for the marginally uncompetitive technologies.

Figure 7 illustrates market lock-out (and lock-in) for four technologies. For simplicity of discussion, we assume that a standard-sized plant is 200 megawatts (composed of one or multiple generation units at a single site), and that all plants use the same fuel inputs. To simplify the illustration, we also assume that the efficiencies and other inputs are the same. In this case, assuming no subsidization, the mature technology for the"next unit" (unit 1 on the horizontal axis), would always "win" the market. Because the other "unit 1" technologies are not economical in comparison with the mature technology, they are not built, and learning-by-doing does not occur for them—market lock-out.

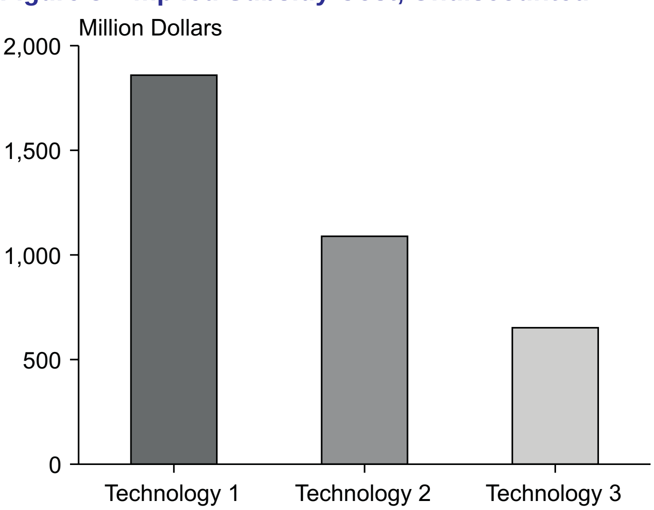
Assuming that the three highest-cost technologies were somehow subsidized until they became competitive with the original lowest-cost technology, Figure 8 illustrates the minimum subsidy each would require until sufficient learning-by-doing was accomplished for the

Figure 7. Lock-Out Example



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

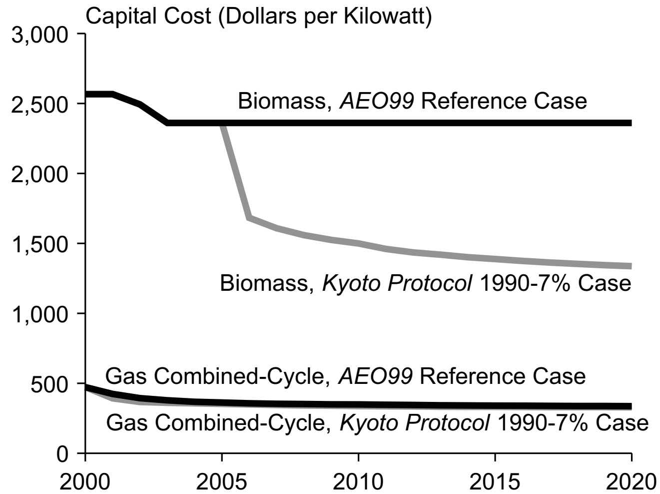
Figure 8. Implied Subsidy Cost, Undiscounted



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

technology to penetrate the market on its own.[19] Of course, to do a more complete analysis, all the costs and benefits, including efficiency, co-products, and environmental considerations, would have to be included. To illustrate the importance and impact of learning-by-doing in the EMM, Figure 9 shows the cost paths for gas combined-cycle and biomass generation from two

Figure 9. Learning in *AEO99* and in the Kyoto Protocol 1990-7% Case



Sources: Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998), and Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03 (Washington, DC, October 1998).

recent EIA analyses—the *Annual Energy Outlook 1999* (*AEO99*) and *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity* (*Kyoto Protocol*).[20]

Given the severe fuel price impacts of the *Kyoto Protocol* 1990-7% case, which projects a “carbon price” of $348 per ton of carbon in 2010, biomass generation capacity[21] is rapidly adopted (about 7 additional gigawatts), and costs decline by about 35 percent within a span of a few years as a result of about 7 gigawatts of cumulative adoption and resulting learning between 2005 and 2008. The gas combined-cycle technology still is projected to be adopted heavily in both cases (more than 25 gigawatts of new capacity between 2005 and 2008), because it is economical in both cases, and there is little difference in the learning path between the two cases.

Tables 1 and 2 summarize the major generation technologies and characteristics assumed for *AEO99*. Normally, either the current capital cost (dollars per kilowatt) if the technology is mature, or the cost of the fifth unit (*n*th-of-a-kind) if the technology is in the early phases of adoption, is input to the model. To determine the first-of-a-kind cost, note that the fifth-of-a-kind[22]

[19] Energy Information Administration, *Modeling Technology Penetration*, NEMS Component Design Report (Draft, April 7, 1993).

[20] The two cases used are from Energy Information Administration, *Annual Energy Outlook 1999*, DOE / EIA-0383(99) (Washington, DC, December 1998), and Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR / OIAF / 98-03 (Washington, DC, October 1998). In the Kyoto Protocol analysis, one of the cases analyzed (the 1990-7% case) required the United States to meet a carbon emissions target of 7 percent below 1990 levels entirely through domestic actions.

[21] A biomass generator can be viewed as a biomass material handler and gasifier at the front end of a gas combined-cycle system. The “front end” of the biomass unit processes the biomass material (shreds it to an acceptable size and consistency) and then gasifies it. Material handling problems, which tend to gum up and seize the front-end processing, currently are expected to cause significant increases in scheduled and unscheduled maintenance. Both parts (the front-end and gas combined cycle) are expected to decline in costs although the material handling component and gasifier have the most room for learning.

[22] $n = 5$ for the current implementation.

represents about 2.5 doublings of capacity. If 10 percent is the cost reduction for each doubling of capacity, then the first-of-a-kind cost, without applying any technological optimism factor, is 26.9 percent higher than the fifth-of-a-kind. Applying the optimism factor to the first-of-a-kind cost results in the ultimate first-of-a-kind cost. For example, the fifth-of-a-kind cost of a biomass generation plant is $1,448 per kilowatt (in 1997 dollars). The optimism factor assigned to biomass is 1.19, which implies that there are some significant uncertainties related to biomass material handling and processing. The true first-of-a-kind cost is 1.19×1.2691, or 52 percent above the mature fifth-of-a-kind cost. Learning rates are estimated and input for each technology and each learning interval (Table 2).

Table 1. *AEO99* Cost and Performance Characteristics for New Generating Technologies

Technology	Size (Megawatts)	Capital Costs (1997 Dollars per Kilowatt)		Variable O&M Costs (1997 Mills per Kilowatthour)	Fixed O&M Costs (1997 Dollars per Kilowatt)
		1st-of-a-Kind	*n*th-of-a-Kind		
Scrubbed Coal	400	1,093	1,093	3.33	23.03
Integrated Gas Combined Cycle	428	1,606	1,091	0.79	32.13
Gas/Oil Steam Turbine	300	1,004	1,004	0.51	30.70
Conventional Gas/Oil Combined Cycle	250	445	445	0.51	15.35
Advanced Gas/Oil Combined Cycle	400	575	405	0.51	14.23
Conventional Combustion Turbine	160	329	329	0.10	6.35
Advanced Combustion Turbine	120	461	325	0.10	9.01
Fuel Cells	10	2,146	1,458	2.05	14.74
Advanced Nuclear	600	2,371	1,570	0.41	56.29
Biomass	100	2,205	1,448	5.32	44.00
Municipal Solid Waste	30	N/A	5,892	5.53	0.00
Geothermal	50	N/A	1,831	0.00	85.90
Wind	50	1,109	776	0.00	25.92
Solar Thermal	100	2,904	1,907	0.00	46.58
Solar Photovoltaic	5	4,162	2,903	0.00	9.82

Source: Energy Information Administration, *Assumptions to the Annual Energy Outlook 1999*, DOE/EIA-0554(99) (Washington, DC, December 1998).

Table 2. *AEO99* Technological Optimism and Learning Factors for New Generating Technologies

Technology	Optimism Factor	Learning Factors		
		Units 1 to 5	Units 6 to 40	Units 40 and Above
Scrubbed Coal	1.00	NA	NA	0.03
Integrated Gas Combined Cycle	1.16	0.10	0.05	0.03
Gas/Oil Steam Turbine	1.00	NA	NA	0.03
Conventional Gas/Oil Combined Cycle	1.00	NA	NA	0.03
Advanced Gas/Oil Combined Cycle	1.12	0.10	0.05	0.03
Conventional Combustion Turbine	1.00	NA	NA	0.03
Advanced Combustion Turbine	1.12	0.10	0.05	0.03
Fuel Cells	1.16	0.10	0.05	0.03
Advanced Nuclear	1.19	0.10	0.05	0.03
Biomass	1.19	0.10	0.05	0.03
Municipal Solid Waste	NA	NA	NA	NA
Geothermal	NA	0.10	0.05	0.03
Wind	1.00	0.08	0.05	0.05
Solar Thermal	1.19	0.10	0.05	0.03
Solar Photovoltaic	1.12	0.10	0.05	0.03

Source: Energy Information Administration, *Assumptions to the Annual Energy Outlook 1999*, DOE/EIA-0554(99) (Washington, DC, December 1998).

Issues Associated with the EMM Implementation

The rate of learning-by-doing in the EMM hinges critically on three parameters: (1) the rate at which cost reductions occur with production, (2) the definition of standard unit size, and (3) how much "learning" actually can take place when the vendor is, for all intent and purposes, building plants in the same year. The problem encountered with learning for electricity generation is that a significant portion of installed costs are site-specific, and most equipment installations retain a certain level of customization; hence, learning-by-doing can be divided between advances in the technology and advances in the installation. For example, some European experts assert that learning for wind turbine technology has undoubtedly slowed to about 2 to 8 percent for every doubling of worldwide capacity for the best wind sites,[23] and 4 to 6 percent has recently been recommended.[24] Considerable learning remains with respect to siting wind turbines in more difficult terrain and in lower quality wind resource areas. On the other hand, gas combined-cycle systems—which are the most modular, turnkey systems available, with the fewest customization requirements—reflect learning through modularization and system integration to boost efficiency and reduce total installation costs. The extent to which further learning can progress in each of these areas (technology and siting) remains a difficult, technology-specific issue.

It is unclear how much learning can be achieved from simultaneous construction of large-scale electricity generation equipment. Typically, it takes some time (often years or decades)[25] before accrued operational experience is fed back to the manufacturer. There may be a limit to the maximum "learning" that can be achieved in one year. Further, the manufacturer is often obliged to make adjustments on existing equipment to meet the contractual operational specifications. Thus, the first quoted cost is often larger than the bid, and the equipment is often customized.

Summary

Learning-by-doing (for manufacturers) and learning-by-using (for consumers) have been shown by numerous authors to be important determinants of the rate of adoption of new technologies. Manufacturing learning reduces the cost of equipment production and makes the equipment more economical for adoption. Increased consumer learning (familiarity with and use of a product) can increase the likelihood that more of the technology will be adopted. These forces work in tandem in the market and are difficult, if not impossible, to separate. In NEMS, the two learning concepts are integrated and implemented in combination. However, because technologies and their adoption are represented somewhat differently in the various NEMS modules, based on the markets they represent, the treatment of technological learning in NEMS also differs by sector. Despite the uncertainties and difficulties of representing technological learning, its importance for the effective analysis of proposed technology policies is undeniable, and it must be represented in the modeling framework.

[23]For example, see L. Neij, "Use of Experience Curves To Analyze the Prospects for Diffusion and Adoption of Renewable Energy Technology," *Energy Policy*, Vol. 23 (1997), pp. 1099-1107; and L. Neij, *Dynamics of Energy Systems: Methods of Analyzing Technology Change* (Doctoral Dissertation) (Lund University, Sweden: Department of Environmental and Energy Systems Studies, 1999).

[24]International Energy Agency, International Workshop on Experience Curves for Policy Making (Stuttgart, Germany, May 10-11, 1999). It was noted at the conference that the most recent advance in improving wind capacity factors was the use of larger wind blades. Participants also noted that further increases in wind blades could not be accommodated without an overall redesign of wind systems and at least some initial cost increases.

[25]Experience with nuclear plants suggests that we cannot simply add up capacity every year, because time, operating experience, and engineering resources are required to achieve significant learning.

Appendix
Overview of NEMS

The National Energy Modeling System (NEMS) was developed by the Energy Information Administration (EIA) in 1993. NEMS is a large, regional, modularly designed, technology-rich, energy-economy model that solves for annual equilibrium in U.S. energy markets. It is particularly well suited to address policy issues focusing on technological change.

The Integrating Module (Figure A1) controls communications in NEMS through a common shared data structure. As an oversimplified representation of the equilibration process, the demand modules can be viewed as receiving fuel prices by end use and returning the quantity of each fuel demanded. Technology choice is determined within each sector and is not part of the equilibration process.[26] The oil and gas supply modules receive the demand for each fuel and the associated prices and provide a supply curve based on drilling investments, drilling activity, and reserve additions. Coal supply curves are based on labor productivity.

The conversion modules[27] are the most complex and the largest models within NEMS. The electricity module receives the delivered prices of fossil fuels, the demand for electricity, the current generation mix available, and environmental policies and regulations to determine the least-cost dispatch of plants, fuel consumption to generate electricity, and electricity prices. The electricity capacity expansion submodule uses the same information as the electricity dispatch module, along with the menu of technologies available for construction, expected fuel prices, and electricity demand and determines the least-cost plan that meets all identified environmental constraints.

The NEMS representation of energy markets focuses on four important interrelationships: (1) interactions among the energy supply, conversion, and consumption sectors; (2) interactions between the domestic energy system and the general domestic economy; (3) interactions between the U.S. energy system and world energy markets for oil, liquefied natural gas, and coal (and gas and electricity trade within North America); and (4) the interaction between current production and consumption decisions and expectations about the future.

- **Interaction Among Domestic Energy Supply,** Conversion, and Consumption. Interaction among domestic energy supply, conversion, and consumption is assured through the representation of simultaneous competitive markets in achieving year-to-year energy-economy equilibrium subject to the equipment constraints imposed by a "bottom-up" approach. A "bottom-up" approach to modeling begins by modeling the agents at a relatively disaggregated level (e.g., households, which determine from their decision rules the relative number of home and equipment purchases for each type of new home). The actual decisions at the household level are summed to total purchases, equipment, and energy consumption. The prices paid and quantities demanded of each fuel at end-use are in balance with the supply and prices offered.

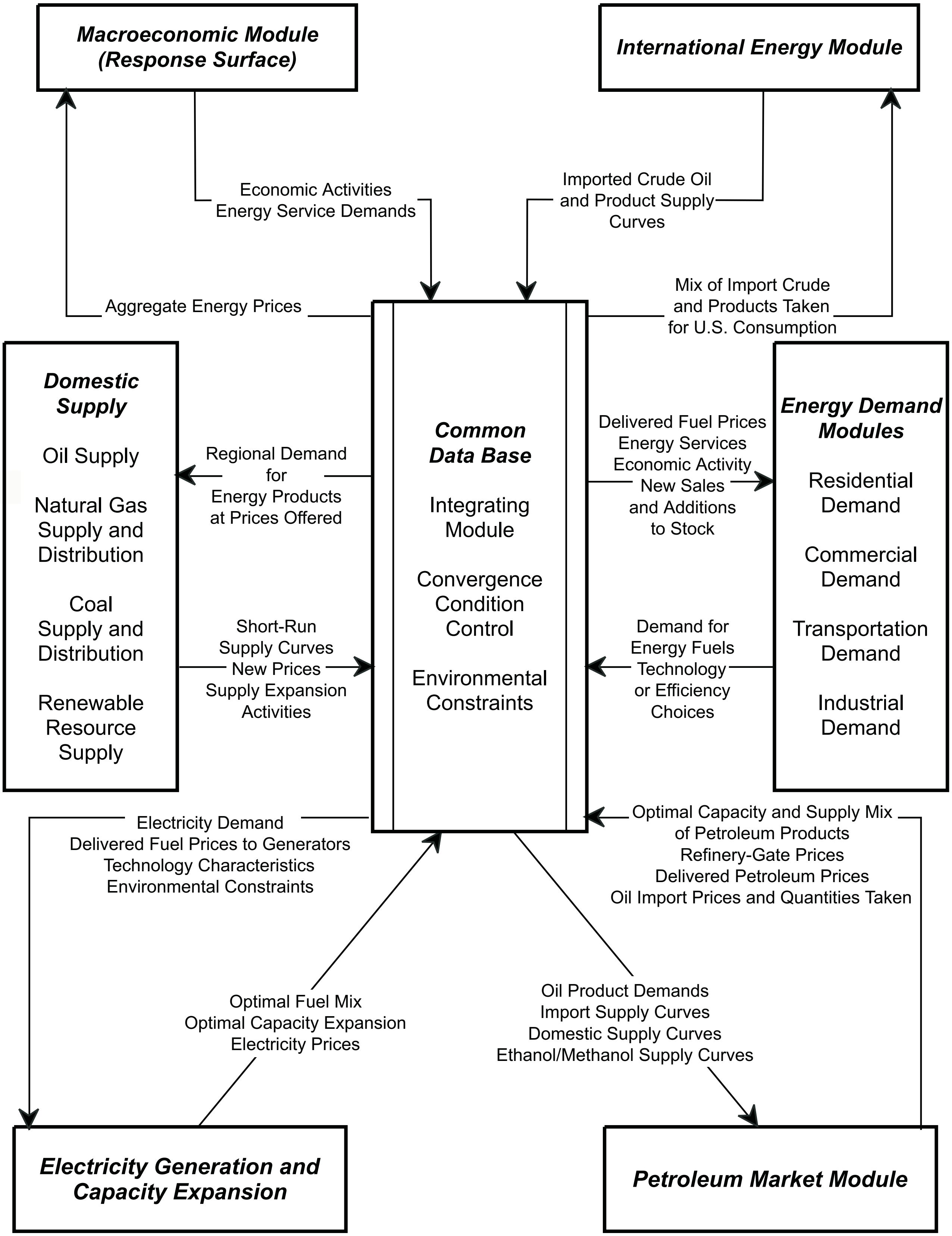
- **Domestic Energy System / Economy Interactions.** The general level of economic activity in sectoral and regional detail has traditionally been used as an explanatory variable or "driver" for projections of energy consumption and prices. In reality, energy prices and other energy system activities themselves influence the level of economic activity. NEMS is designed to capture this "feedback" between the domestic economy and the energy system. The macroeconomic component of NEMS is a reduced-form version of the DRI macroeconomic model. Changes in energy prices from a DRI reference case cause changes to macroeconomic variables such as disposable income, new car sales, and industrial output, while changes in the macroeconomy cause changes to energy service demands.

- **Domestic and World Oil Market Interactions.** The world oil price is a key variable in domestic energy supply and demand decisionmaking. As a result, world oil price assumptions have been a key starting point in the development of energy system projections. In fact, the U.S. energy system itself exerts a significant influence on world oil markets, which in turn influences the world oil price—another example of a "feedback" effect. World energy market supply and demand are first specified outside NEMS by a world oil model.[28] Given this, NEMS models the interactions between the U.S. and world oil markets through the use of import crude and product supply curves. Changes in U.S. oil markets affect world supply and demand. As a result, domestic energy system projections and the world oil price are made internally consistent.

[26] See Energy Information Administration, *The National Energy Modeling System: An Overview*, DOE/EIA-0581(98) (Washington, DC, February 1998).
[27] The electricity and refinery sectors are the conversion modules.
[28] Crude oil and product supply curves are produced using the World Oil Refining, Logistics, and Demand Model.

- **Economic Decisionmaking Over Time.** Production and consumption of energy products today are influenced by past decisions to develop energy resources and acquire energy-using capital. Similarly, the production and consumption of energy in a future time are influenced by decisions made today and in the past. Current investment decisions depend on expectations about future market circumstances. For example, the propensity to invest now to develop alternative energy sources increases when future energy prices are expected to increase. Recognizing that the residential and commercial energy markets form and respond differently to price expectations than do the generation and industrial sectors, NEMS allows different kinds of foresight assumptions to be applied differentially to its individual submodules. This flexibility allows the consequences of different planning horizons and consumer preferences to be incorporated in NEMS projections.

Figure A1. Structure of the National Energy Modeling System



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Employment Trends in Oil and Gas Extraction

by
James M. Kendell

The number of wells drilled is one of the most significant factors affecting upstream employment in the oil and gas extraction industry. Drilling is affected in turn by prices, costs, taxes, and technology. The share of successful wells accounted for by natural gas, the share of total U.S. oil production accounted for by operations in Alaska, and the share of total U.S. oil and gas production accounted for by offshore activity also have significant impacts on upstream employment. "Service" jobs in the oil and gas extraction industry, including drilling and geological services, are more responsive to drilling levels than "production" jobs. The leading oil and gas producing States are less affected by changes in drilling and production than are States with many marginal wells. This paper shows that oil and gas extraction jobs are becoming less important to the State and national economies.

Introduction

Between October 1997 and December 1998 the imported refiner acquisition cost of a barrel of oil dropped by almost half, from $18.73 per barrel to $9.39 per barrel.[1] According to the Bureau of Labor Statistics (BLS), U.S. Department of Labor, employment in the upstream oil and gas industry had declined by more than 50,000 jobs by February 1999, leaving the United States with less than half the number of oil and gas extraction jobs it had during the early 1980s, when oil prices were more than four times as high in real terms.[2]

This paper presents an econometric model that can be used to forecast industry employment. On an average annual basis, the number of upstream oil and gas jobs was 325,900 in 1998. Based on the model's parameters and inputs from the *Annual Energy Outlook 1999* (*AEO99*), the average level of employment is expected to decline to 273,000 in 2000.[3] These projections are based on a reference case in which the average imported refiner acquisition cost (world oil price) is expected to be $13.97 a barrel in 2000, and the average lower 48 natural gas wellhead price is expected to be $2.10 per thousand cubic feet for the year, both in 1997 dollars. If prices—and therefore, drilling—turn out to be higher, the level of employment is also expected to be somewhat higher than in the reference case.

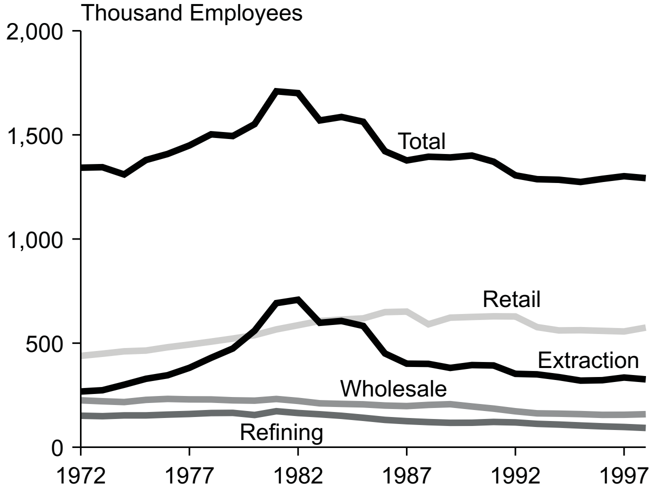
Regardless of what happens in the short run, industry employment can be expected to increase between now and 2010. Based on the activity levels expected in the *AEO99* reference case, employment in 2010 is projected to equal approximately 350,000, in large part because of increased drilling. In the low world oil price case, employment in 2010 is projected at 329,000 jobs. In the high world oil price case, 2010 employment is projected to grow to 372,000.

Employment in the Upstream Sector

Oil and gas extraction activities are part of a larger petroleum industry, including petroleum refineries, wholesale terminals, and gasoline stations. Since 1972, employment in the entire petroleum industry has ranged from 1.3 to 1.7 million workers (Figure 1). Employment peaked in 1981, when the real imported refiner acquisition cost of a barrel of crude oil was almost $63 a barrel in 1997 dollars.[4] Since then, petroleum industry employment has declined, as the numbers of oil and gas wells drilled, operating refineries, and wholesale jobbers have declined.

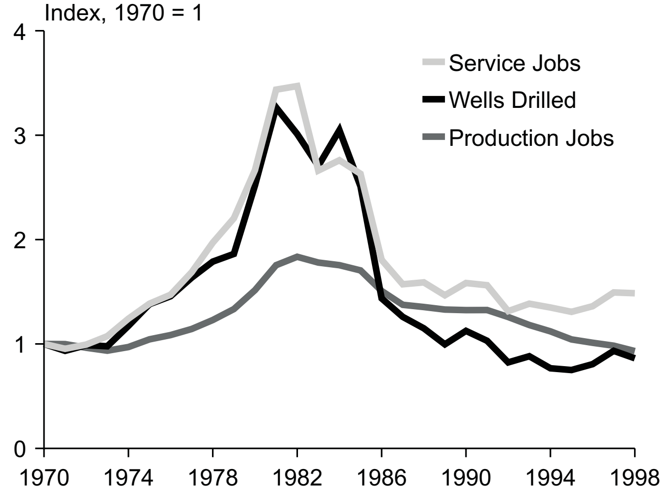
[1]Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(99/05) (Washington, DC, May 1999), Table 9.1, p. 111.
[2]U.S. Department of Labor, Bureau of Labor Statistics, National Employment, Hours, and Earnings, web site http://146.142.4.24/cgi-bin/srgate: oil and gas extraction, eeu10130001.
[3]The econometric analysis was performed by Kevin F. Forbes, Science Applications International Corporation.
[4]Calculated from Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998), Table 5.19, p. 155.

Figure 1. U.S. Petroleum Industry Employment, 1972-1998



Source: U.S. Department of Labor, Bureau of Labor Statistics, National Employment, Hours, and Earnings, web site http://146.142.4.24/cgi-bin/srgate. Total calculated from the following series: oil and gas extraction, eeu10130001; petroleum refining, eeu32291001; asphalt paving and roofing materials, eeu32295001; pipelines, excluding natural gas, eeu41460001; petroleum wholesaling, eeu53517001; and gasoline service stations, eeu60554001.

Figure 2. Production and Service Jobs and Wells Drilled, 1970-1998



Source: U.S. Department of Labor, Bureau of Labor Statistics, National Employment, Hours, and Earnings, web site http://146.142.4.24/cgi-bin/srgate: oil and gas production, eeu10131001; oil and gas services, eeu10138001; Energy Information Administration, *Annual Energy Review*, DOE/EIA-0384(97) (Washington, DC, July 1998), Table 4.4, p. 93; and Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(99/05) (Washington, DC, May 1999), Table 5.2, p. 83.

This analysis focuses on employment in the oil and gas extraction (or upstream) industry. In collecting data on the industry, the BLS considers two primary sectors—a service sector and a production sector. Work in the service sector is performed on a contract basis. Service jobs include drilling, geological services, and well repair work performed under contract. Although some drilling occurs in the BLS production sector, most occurs in the service sector. Employment in both sectors increased in the wake of the sharp rise in real oil prices in the late 1970s but has fallen almost every year since 1982 (Figure 2). Since 1982, the level of employment in both sectors has declined by almost 400,000. As of 1998, the average level of employment in the oilfield service sector was 186,100, and the production sector had an average employment level of 135,000.

The decline in employment from 1982 to 1998 can largely be attributed to the sharp decline in oil and gas drilling over the same period. From 1982 to 1998 the number of wells drilled annually fell from about 84,400 to 24,200 (Figure 2). The principal factor contributing to the decline was the collapse of oil prices after 1985. For example, the price of oil, as measured by the imported refiner acquisition cost, fell from $53.33 a barrel (in real 1997 dollars) in 1982 to $11.97 in 1997, and the average wellhead price of natural gas declined by half in real terms. Prices affect jobs in the upstream oil and gas industry through their effects on drilling and production. Prices tend to have an immediate effect on exploratory activity, including seismic studies and wildcat drilling, which tends to last only a few months. Their initial impact on production activities—such as developmental drilling and operation of lease equipment, which tend to last for many years—is smaller. Thus, employment increases when oil prices rise, but not as much as prices.

Other factors that have contributed to the decline in drilling and employment include technological advances (such as horizontal drilling), which have made it possible to extract more oil and gas with fewer wells and fewer workers. Factors that have tended to mitigate the downward trend in drilling and employment include lower drilling costs and favorable tax policies. For example, in 1982 the average gas well cost $1.39 million (1997 dollars) to drill, but by 1997 average costs had declined almost continuously to $723,000 per well.[5] Tax policies such as tax credits for unconventional drilling and royalty relief for deepwater production have also served to moderate the decline in drilling and employment.

Technology has had both positive and negative impacts on jobs over the 1982-1997 period, creating new jobs in data processing and interpretation but reducing the need for oil and gas drilling platforms. Major advances

[5]Calculated from American Petroleum Institute, *1982 Joint Association Survey on Drilling Costs* (Washington, DC, November 1982); and *1997 Joint Association Survey on Drilling Costs* (Washington, DC, November 1997).

in data acquisition, data processing, and the technology of displaying and integrating seismic data with other geologic data have created computer and analysis jobs but reduced the number of exploratory wells needed. The introduction of subsea well technologies, tension leg platforms, and production spars have opened up vast new and promising areas for exploration in the deep-water areas of the offshore that had been inaccessible, creating more offshore jobs but reducing conventional drilling activity. Another significant cost-saving technology, adopted in the later part of the 1980s, was horizontal drilling. Most reservoirs are wider than they are deep, and drilling a horizontal, as opposed to a conventional vertical well enables more of the reservoir to be exposed to the wellbore. Fewer wells need to be drilled, but more skills are needed in data analysis and directional drilling.

Finally, the decline in employment has been ameliorated by the shift in drilling in favor of natural gas. In 1982, the number of oil well completions was more than double the number of gas completions. By 1993, the number of gas completions had exceeded the number of oil completions. In October 1998 twice as many successful gas wells were drilled as oil wells, and in February 1999 three times as many gas wells were drilled.[6] This shift in the composition of drilling has tended to slow the rate of decline in employment, because gas wells are generally deeper than oil wells and hence require more labor inputs.

The October 1997 to December 1998 decline in upstream employment was similar to the decline that occurred in the 15-month period from October 1990 to January 1992. Some 31,300 jobs were reported lost in the most recent period and 34,700 in the early 1990s period. During both periods the imported refiner acquisition cost of a barrel of oil dropped by about half.[7] The October 1997 to December 1998 period was quite different from January to July 1986, another period when oil prices fell by half. During those 6 months in 1986, 127,000 oilfield workers lost their jobs, because some producers and lenders began shifting their expectations for future prices from a view that oil prices would continue to rise to a view that they would hold steady, varying around an average. This was primarily because in late 1985 Saudi Arabia—facing increasing needs for oil revenue—abandoned the role of swing producer that it had played during the first half of the 1980s. In the most recent two periods of job loss, in contrast, the industry's fundamental price outlook was largely unchanged.[8]

Over a few months' time, even a doubling in prices historically has had little immediate effect on upstream oil and gas employment. From June to October 1990, imported refiner acquisition costs of crude oil more than doubled in the run-up to the invasion of Kuwait by Iraq. But in those 4 months only 3,500 oil and gas extraction jobs were added in the United States, less than a 1-percent increase. For rising prices to create new upstream jobs, they must be sustained for a substantial length of time—more than just a few months—because producers need to be confident that they will get an adequate return on their investments.

Economic Impacts

In the 14 months from January 1998 to March 1999, the five largest oil and gas producing States (Texas, Louisiana, Oklahoma, California, and Alaska) suffered proportionally fewer job losses than their production share. In 1997 the five largest oil and gas States (Figure 3) produced 77 percent of U.S. oil and gas; however, they suffered only 41 percent of the total 46,700 job losses from January 1998 to March 1999.[9] This was because a larger share of marginal oil and gas production is outside these five States and because company headquarters and producing sector employees who contribute to the operation of oil and gas production in many States are located in these five States.

As the overall number of upstream oil and gas jobs has declined, they have become less important to State economies. In Texas, the State that has the most oil and gas extraction jobs and produces the most oil and gas, extraction jobs peaked in January 1982 at 313,700 or 5.0 percent of the total Texas labor market.[10] By March 1999 the preliminary estimate for employment in upstream oil and gas had fallen to 149,800, less than half of the

[6]Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(99/05) (Washington, DC, May 1999), Table 5.2, p. 83.

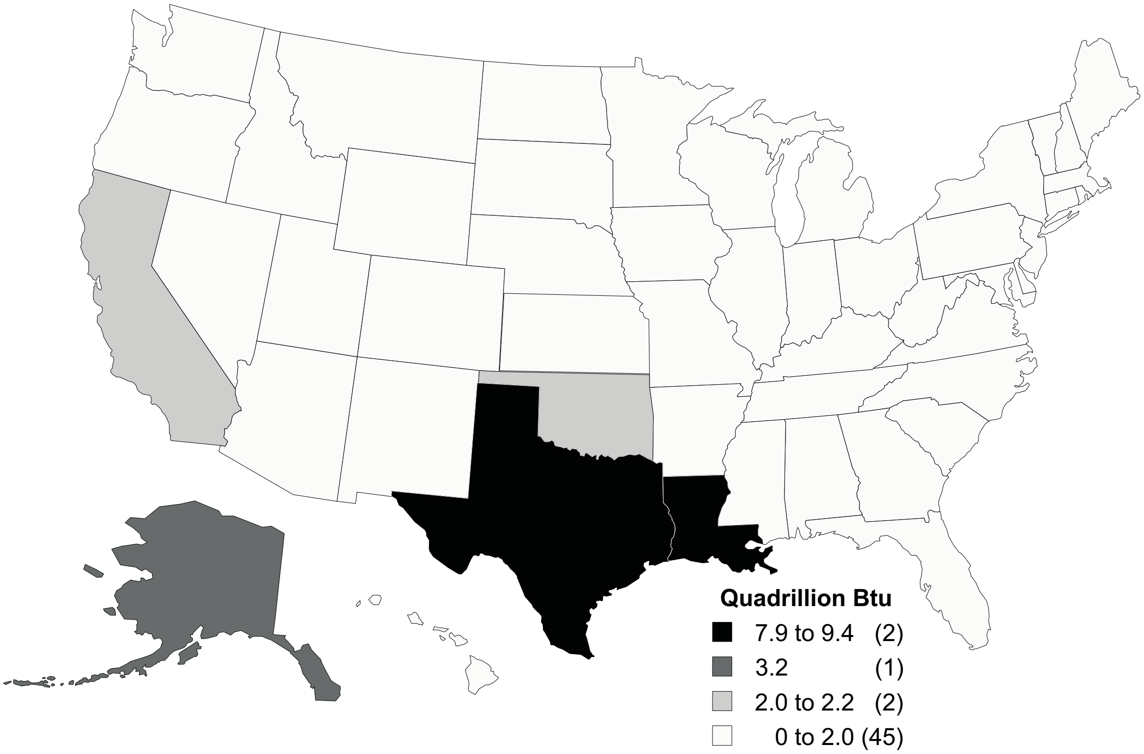
[7]U.S. Department of Labor, Bureau of Labor Statistics, National Employment, Hours, and Earnings, web site http://146.142.4.24/cgi-bin/srgate: oil and gas extraction, eeu10130001; Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(99/04) (Washington, DC, April 1999), Table 9.1, p. 111; and Energy Information Administration, *Historical Monthly Energy Review*, DOE/EIA-0035(73-92) (Washington, DC, August 1994), Table 9.1, p. 250.

[8]"Firms Adjust to Outlook for Continued Weak Prices," *Oil and Gas Journal* (August 19, 1985), pp. 41-44; and *Survey of Forecasters* (Tulsa, OK: PennWell Publishing Company, various issues, 1988-1998).

[9]U.S. Department of Labor, Bureau of Labor Statistics, State Employment, Hours, and Earnings, web site http://146.142.4.24/cgi-bin/srgate: Alaska, sau0200001130021; California, sau0600001000011, sau0600001100021, sau0600001140021; Louisiana, sau2200001130021; Oklahoma, sau4000001130021; Texas, sau4800001130021. In California the change in upstream employment was assumed to be mining minus metal mining minus nonmetallic minerals. March data are preliminary.

[10]L. Jones and M. Dermit, "Tough Times for Texas Oil," *Texas Labor Market Review* (February 1999), p. 3.

Figure 3. Oil and Gas Production by State, 1997



Source: Calculated from Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1997 Annual Report*, DOE/EIA-0216(97) (Washington, DC, December 1998), pp. 20 and 28.

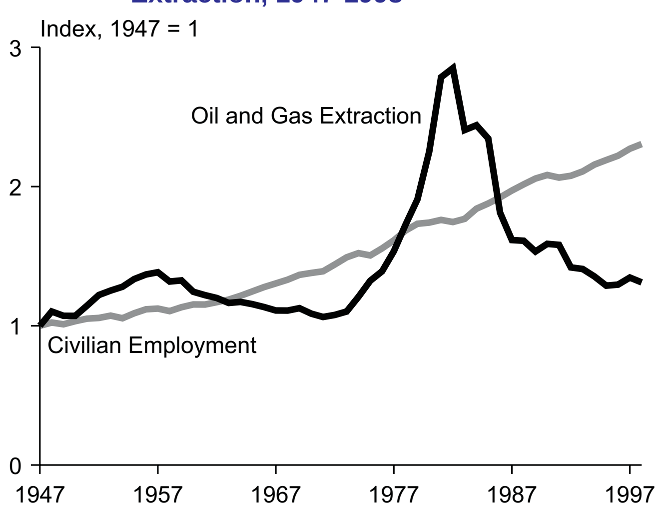
peak, and accounted for only 1.6 percent of the State's total employment.[11] While oil and gas jobs declined, the rest of the Texas economy grew, boosting total employment by more than 2.8 million over 18 years. As a result, the recent low oil prices have not hurt the Texas economy as much as they did in the 1980s.

A similar story can be told at the national level. When oil and gas extraction employment peaked in 1982, 0.7 percent of civilian workers were directly employed by the upstream petroleum industry. By 1998, however, only 0.2 percent of civilian workers were directly employed by the upstream petroleum industry. While the number of oil and gas extraction jobs has been declining, the number of other civilian workers has been increasing (Figure 4).

A Model of Industry Employment

Employment in the oil and gas extraction sectors was econometrically estimated for both the service and production sectors. The regressions contained the following independent variables (see Appendix): the number of total wells drilled in a year *(Drilling)*, the share of successful wells accounted for by natural gas *(Gas share)*, the share of total U.S. oil production accounted for by operations in Alaska *(Alaska share)*, the share of total U.S. oil and gas production accounted for by offshore activity *(Offshore share)*, and a structural change variable *(New Era)*.

Figure 4. Changes in Total Civilian Employment and Employment in Oil and Gas Extraction, 1947-1998



Source: Calculated from U.S. Department of Labor, Bureau of Labor Statistics, Labor Force Statistics from the Current Population Survey, civilian employment, lfu11000000, and National Employment, Hours, and Earnings, oil and gas extraction, eeu10130001, http://146.142.4.24/cgi-bin/srgate.

[11]Texas Workforce Commission, Employment Estimates, web site http://www.twc.state.tx.us/lmi/lfs/type/currentestimates/currentestimatescurrent.html (March 1999).

The level of drilling activity was included as an explanatory variable because employment is closely tied to the demand for the geological, construction, and geophysical services needed to drill a well. Oil and gas prices provide the foundation for making a decision about whether to drill a well, but job loss and creation are more closely related to the actual level of drilling.[12] For example, between January 1996 and August 1997, when oil and gas prices were largely flat, drilling increased by about 30 percent, in part because of expectations of higher future prices. Reflecting the increase in the level of drilling, the level of upstream service employment increased by almost 20 percent or approximately 30,000 employees.

The level of employment depends not only on the number of wells drilled but also on the type of wells drilled. For this reason, the share of successful wells that are classified as gas wells was included as an independent variable. The Alaska share of oil production and the offshore share of total oil and gas production were included as variables to account for the fact that the level of drilling in those locales is a relatively poor proxy for their overall activity levels. Offshore drilling accounts for less than 5 percent of total drilling, but because of the nature of the wells—substantially more expensive, but also more productive than onshore wells—the offshore is important to upstream employment.

The model also recognizes that the structure of the industry changed between 1970 and 1997. One of the most important changes is the increased importance of both offshore operations and operations in Alaska. Previously, activity in those locales played only a very minor role in determining the overall level of U.S. upstream employment. That is no longer the case, however, given the reduced industry focus on lower 48 onshore drilling, which has become less profitable. Reduced industry drilling in the lower 48 onshore resulted, in part, from the increase in investment opportunities outside the United States after the fall of the Berlin Wall and the increased likelihood of returns on those investments. To incorporate this "regime change," the coefficients on these variables were permitted to change after 1990 through the inclusion of the variable *New Era*, which is a binary variable equal to 1 after 1990.

To allow for nonlinearities, the employment levels and level of drilling were represented in terms of their natural logarithms. The equations were estimated with annual data from 1970 through 1997. Employment levels in the "service" and "production" sectors were formulated using two separate equations, but they were estimated together using the seemingly unrelated regression technique, so as to obtain more efficient estimates. The model explains more than 99 percent of the variation in employment levels in both sectors over the sample period. The parameters are reported in the Appendix to this paper. All the parameters were statistically significant.

Other model specifications were considered. For instance, it was hypothesized that employment could be affected by the proportion of drilling that is successful—i.e., that a higher success rate, other things being equal, would result in more wells being completed for production and hence in more employment. It was also hypothesized that the overall level of production as well as wellhead revenues could contribute explanatory power to the model. However, the empirical results did not support any of these hypotheses, and hence the variables were excluded from the forecasting equation.[13] All the estimated coefficients were tested for evidence of structural change, as discussed above, but the results were included in the forecasting equation only when there was statistically significant evidence of structural change.

This analysis accounts only for direct oil industry jobs, not the additional, associated jobs that would be affected in the oil and gas retail and consumer service industries, at manufacturers working on oil industry projects, or in pending oil company mergers. Local department stores, automobile dealers, and even school districts can be expected to suffer during a period of low oil prices, as incomes and property values decline. Manufacturers far distant from the oilfields might also suffer a business decline in a period of low oil prices.[14] Shrinking revenues also force oil companies as well as individuals to search for ways to cut costs. In addition to the recently completed merger of British Petroleum with Amoco, the largest prospective oil company merger in U.S. history, between Exxon and Mobil, is pending. On the other hand, lower oil prices can be expected to stimulate economic activity in the consuming sectors and, therefore, increase the number of jobs in the rest of the economy. Oil is an input to production for many industrial and

[12]Previous studies have found that the direct effect of increased oil and gas prices is small in the short run but more significant when price increases are sustained. See T. Hogarty and B. Tierney, *Jobs and Payrolls in the Petroleum Industry: Description and Analysis of the Declines During 1981-1993*, Research Study #077 (Washington, DC: American Petroleum Institute, February 1995).

[13]A recent analysis of a pooled cross-section time series data set of employment for 40 large oil companies active in the Gulf of Mexico in 1979 and 1989 found that several financial variables were significantly related to levels of employment, including the percentage of institutional stock ownership, change in the value of reserves, debt-to-equity ratio, and the stock price. See V. Baxter, "The Impact of Financial Restructuring and Changes in Corporate Control on Investment and Employment in the U.S. Petroleum Industry," *Sociological Quarterly*, Vol. 40, No. 2 (Spring 1999), pp. 269-291.

[14]A few percent of the vendors for the Mars Tension Leg Platform in the Gulf of Mexico were located in each of the States of California, Illinois, and New York, for example. Private communication, Rich A. Pattarozzi, President, Shell Deepwater Development, June 8, 1999.

manufacturing processes, and lower prices will lead to increased output and more jobs.[15]

Forecasting the Level of Employment

Based on the econometric model discussed above and the *AEO99* forecasts of drilling and production, overall employment in the oil and gas extraction sector should average 286,000 in 1999 and 273,000 in 2000. Future growth in employment in the upstream oil and gas sector depends largely on wells drilled and the share of oil and gas being produced from offshore areas and Alaska. For 1999, the *Annual Energy Outlook* projected a drilling level of 20,000 wells, based on a refiner acquisition cost of a barrel of imported crude oil averaging $13.25 a barrel and a lower 48 natural gas wellhead price averaging $2.09 per thousand cubic feet (both in 1997 dollars). The National Energy Modeling System uses these prices—in conjunction with data on production profiles, co-product ratios, drilling costs, lease equipment costs, platform costs (for offshore only), operating costs, severance tax rates, *ad valorem* tax rates, royalty rates, State tax rates, Federal tax rates, tax credits, depreciation schedules, and success rates—to estimate discounted cash flows for representative wells for each region, well type, and fuel type. Drilling is then predicted as a function of the expected profitability.[16]

Other forecasters, given their expectations of higher oil prices, project somewhat higher well counts in 1999. The *Oil and Gas Journal* was most bullish in August 1998 at nearly 27,000 wells in 1999 and an average wellhead price of $16.30 per barrel. In November 1998, the Gas Research Institute forecast about 23,000 wells in 1999 and an average wellhead price of $18.82 a barrel. *World Oil*, in its forecast released in February 1999, projected about 21,000 wells in 1999.[17]

In 2000 the *AEO99* projects drilling to fall to 19,000 wells as a result of the lagged effect of oil prices. Oil prices are expected to increase to almost $14 a barrel, and natural gas prices are expected to remain about the same as in 1999. Although prices are expected to be higher in 2000 than 1999, employment would still be affected by project decisions made in 1999 and earlier, when prices were lower. The June *Short-Term Energy Outlook* projects somewhat higher prices for 2000: a $15.94 imported refiner acquisition cost and a $2.20 wellhead natural gas price (1997 dollars).[18] Consequently, employment is likely to be somewhat higher than 273,000. *AEO98* projected 22,200 wells in 2000, based on wellhead prices of $19.49 per barrel for oil and $2.15 per thousand cubic feet for natural gas,[19] which would yield 310,000 jobs, for example.

After 2000, the *AEO99* reference case projects that drilling will rise gradually from a low in 2000 to about 31,500 wells in 2010, and that the share of offshore production will rise from about 25 percent in 1998 to 29 percent in 2010.[20] Such a large increase in drilling is needed to meet increased demand for oil and gas and to offset the declining productivity of oil and gas drilling. Despite increased drilling, oil production is expected to decline from 6.3 million barrels per day in 2000 to 5.6 million barrels per day in 2010. Natural gas production, in contrast, is expected to increase from 19.3 trillion cubic feet to 23.8 trillion. Given these drilling and production levels, oil and gas extraction jobs are expected to rise to about 350,000 in 2010. In the reference case, the world oil price is expected to rise to $21.30 per barrel in 2010 and the lower 48 natural gas wellhead price to $2.52 per thousand cubic feet.

Increased employment by 2010 is expected only in the service sector, not in the production sector (Figure 5). After bottoming out at an average of 146,800 jobs in 2000, service sector employment is expected to rise gradually through 2006 to about 238,000 jobs and remain at that level through 2010 (Figure 6). Through 2006 service employment is expected to increase as drilling increases in response to higher prices and as production shifts to offshore areas, where more services are required. Employment flattens out after 2006, however, because the share of gas wells and the share of offshore production begin to decline as offshore resources decline, even though overall drilling continues to increase. Production employment is expected to fall gradually from 135,000 in 1998 to 109,700 in 2010, as Alaska's production and conventional onshore lower 48 oil production decline.

[15]Brown and Hill infer that a $5 decline in oil prices would raise national employment by 0.4 percent, and they find that employment would increase in 40 States. See S.P.A. Brown and J.K. Hill, "Lower Oil Prices and State Employment," *Contemporary Policy Issues*, Vol. 6 (July 1988), pp. 60-68.

[16]Energy Information Administration, *Documentation of the Oil and Gas Supply Module (OGSM)*, DOE/EIA-M063(99) (Washington, DC, February 1999), Chapter 4.

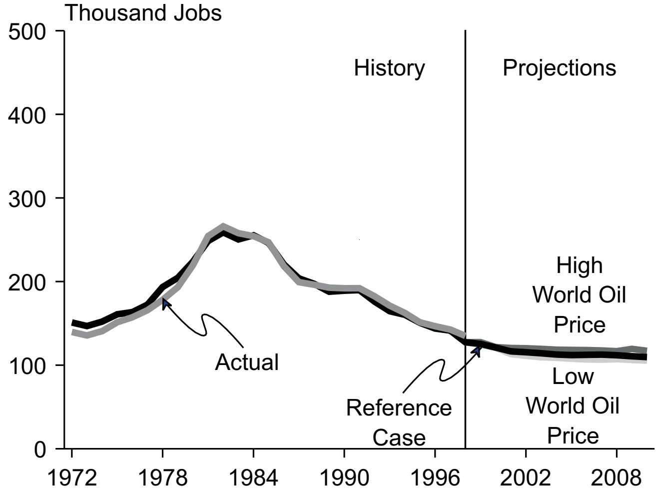
[17]*Survey of Forecasters, Fall 1998*, E1046-F98 (Tulsa, OK: PennWell Publishing Company, January 1999); "A Year of Wait-and-See," *World Oil* (February 1999), p. 58.

[18]Calculated from Energy Information Administration, *Short-Term Energy Outlook* (Washington, DC, June 1999), web site www.eia.doe.gov/emeu/steo/pub/4tab.html, and National Energy Modeling System run AEO99B.D100198A.

[19]Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997), Table A15, adjusted to 1997 dollars.

[20]Energy Information Administration, National Energy Modeling System run AEO99B.D100198A.

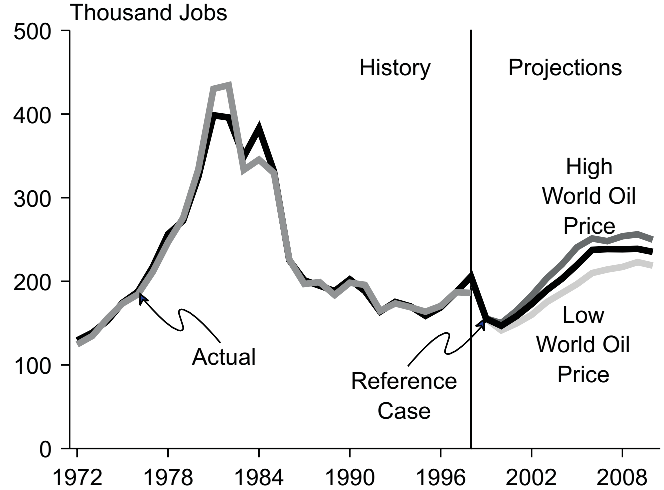
Figure 5. Oil and Gas Production Jobs, 1972-2010



Note: "Production" and "service" jobs comprise most of the "extraction" jobs displayed in Figure 1. A few thousand natural gas liquids jobs are also included in "extraction."

Sources: Actual—U.S. Department of Labor, Bureau of Labor Statistics, National Employment, Hours, and Earnings, web site http://146.142.4.24/cgi-bin/srgate: oil and gas production, eeu10131001. Projections—Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 6. Oil and Gas Service Jobs, 1972-2010



Note: "Production" and "service" jobs comprise most of the "extraction" jobs displayed in Figure 1. A few thousand natural gas liquids jobs are also included in "extraction."

Sources: Actual—U.S. Department of Labor, Bureau of Labor Statistics, National Employment, Hours, and Earnings, web site http://146.142.4.24/cgi-bin/srgate: oil and gas services, eeu10138001. Forecasts—Energy Information Administration, Office of Integrated Analysis and Forecasting.

If oil prices turn out to be higher or lower than projected in the reference case, the number of upstream jobs will also be higher or lower. Upstream jobs range from 329,000 to 372,000 in 2010, based on the outputs of the high and low oil price cases in *AEO99*. The number of wells drilled ranges from 26,700 to 35,500 in those cases. World oil prices range from $14.57 to $29.35 per barrel, and gas prices range from $2.62 to $2.70 per thousand cubic feet.

Similarly, if the number of wells turns out to be higher or lower than projected in the reference case, the number of upstream jobs will also be higher. If the number of wells drilled is 10 percent higher than the reference case projection over the entire forecast, the number of upstream jobs would be 7 percent higher, all other things being equal. A similar falloff in jobs can be expected if the number of wells drilled is 10 percent lower over the entire forecast. The effect of a difference in drilling from the reference case increases slightly over time as the industry adjusts to the new drilling levels. For example, 10 percent more drilling starting in 1997 yields 5 percent more upstream jobs in 2000.

Conclusion

Employment in the oil and gas extraction industry employment averaged 325,900 in 1998 and can be expected to increase between now and 2010. Based on the level of activity expected in the *AEO99* reference case, employment in 2010 is projected to rise to approximately 350,000 jobs, in large part because of increased drilling. "Service" jobs in the oil and gas extraction industry are expected to increase through 2006, whereas "production" jobs are expected to continue their historic decline. The leading oil and gas producing States are less affected by job losses than are States with many marginal wells. Upstream oil and gas employment is diminishing in its importance to the U.S. and State economies.

Appendix

Equations for production and service employment were estimated for this paper. The two equations were:

*ln Production Employment = C + B0 ln Drilling + B1 ln Drilling lagged + B2 Gas share + B3 Offshore share + B4 Offshore share * New Era + B5 Alaska share + B6 Alaska share * New Era*

R-Squared = 0.991578
Rho = 0.706691
Durbin-Watson Statistic = 1.53180
Standard Error of Regression = 0.019489.

ln Service Employment = C + B0 ln Drilling + B1 ln Drilling lagged + B2 Gas share + B3 Offshore share + B5 Alaska share

R-Squared = 0.988744
Durbin-Watson Statistic = 1.40529
Standard Error of Regression = 0.037618.

All coefficients were statistically significant at the 95 percent level of confidence, with the exception of *B2* in the first equation, which was only significant at the 80 percent level of confidence. Where appropriate, the regressions were corrected for autocorrelation.

Results were:

Production Employment

Variable	Estimate	t-Statistic
Constant	1.15750	3.20022
B0	0.17732	6.67386
B1	0.15937	6.13943
B2	-0.13798	-1.41533
B3	2.26616	2.56025
B4	-3.77262	-5.29127
B5	0.99859	5.90676
B6	2.99510	5.13848

Service Employment

Variable	Estimate	t-Statistic
Constant	-4.19156	-12.9422
B0	0.71174	15.5968
B1	0.11778	2.13174
B2	0.76733	4.87936
B3	2.09137	2.89198
B5	0.62681	3.64857

Price Responsiveness in the NEMS Buildings Sector Models

by
Steven H. Wade

This paper describes the responses to changes in fuel prices in the Annual Energy Outlook 1999 (AEO99) versions of the National Energy Modeling System (NEMS) Residential and Commercial Demand Modules. Own-price and cross-price elasticities, both short-run and long-run, are described. Results for price increases and decreases, and for temporary shocks versus permanent changes, are also discussed. Own-price elasticities range from -0.23 for residential electricity (short-run) to -0.87 for commercial distillate (long-run). Cross-price elasticities range from 0.0 to 0.49 (commercial distillate consumption in response to change in natural gas price). These elasticities are also compared with those reported in the literature.

Overview

This paper describes the price responsiveness incorporated into the *Annual Energy Outlook 1999* (*AEO99*) versions of the National Energy Modeling System (NEMS) buildings sector models. The emphasis here on price responsiveness should not be taken to imply that price responsiveness is the main determinant of energy consumption either in NEMS or in general—it is not. Sectoral growth, the development and penetration of new technologies, and the penetration of existing or new end uses all have important effects on long-term energy consumption.

The Residential and Commercial Demand Modules (RDM and CDM) are separate models within NEMS. While the two models generally respond similarly, differences in accounting and equipment choice algorithms result in cases where one model may include effects or exhibit behavior different from the other. In such cases, differences are noted. The discussion of model features and algorithms provided here is intentionally brief, because detailed information is provided elsewhere.[1]

The NEMS buildings sector models exhibit both short-run and long-run responses to changes in energy prices. Conventionally defined, short-run responses are the immediate behavioral effects of a change in energy prices on the intensity of utilization of a fixed stock of energy-consuming capital equipment. Long-run price responses occur through changes in the stock of energy-consuming capital equipment installed in buildings. As described below, for computational tractability, short-run elasticities are computed here as any change occurring in the first year of a price change. Long-run elasticities are computed as a persistent change in price after an interval of 20 years. Examples of short-run responses include adjusting thermostats on heating and cooling equipment, being more or less careful about leaving lights on or equipment running when not in use, or consuming more or less hot water.

The energy-using capital stocks convert energy from its raw potential into the desired end-use services. The NEMS buildings sector models are "stock turnover" models—they alter capital stocks by simulating equipment purchases for new construction, the replacement of worn-out equipment, and the retrofitting of still functioning but economically obsolete equipment.[2]

For buildings, capital service lives generally range from 12 years (e.g., air conditioners and heat pumps) to 30 years (e.g., boilers). Because of the persistence of the equipment stock, full responses to energy price changes

[1]See Energy Information Administration, *Assumptions to the Annual Energy Outlook 1999*, DOE/EIA-0554(99) (Washington, DC, December 1998); *Model Documentation Report: Residential Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M067(99) (Washington, DC, December 1998); and *Model Documentation Report: Commercial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M066(99) (Washington, DC, December 1998).

[2]Equipment that is still capable of providing energy services but has operating costs (fuel and maintenance) greater than the annualized capital and operating costs of newer equipment is called "economically obsolete." The retirement and retrofitting of economically obsolete equipment is simulated in the CDM and adds another dimension to its potential price responsiveness.

occur over an extended interval. Long-run price responses occur in the models through potentially altered equipment purchases that may be projected to occur under different energy price regimes with all other factors and policies affecting energy consumption being equal. During periods of higher energy prices, examples of long-run responses include the purchase of more efficient lighting fixtures and bulbs, adding lighting timers and motion sensors, the purchase of higher efficiency space heating equipment, installing higher R-value insulation, and switching fuels when price increases vary by fuel (e.g., replacing an electric clothes dryer with a natural gas dryer or vice versa).[3] During periods of lower energy prices, the purchasing tendencies simply reverse.

Own-Price Responses

Empirical studies of energy demand generally have found inelastic short-run responses to energy prices—that is, for a given percentage change in energy prices, a less than proportional percentage adjustment occurs in energy consumption.[4] The short-run elasticity parameters in the buildings models are for each individual end use (heating, lighting, etc.). For both models, all end uses except refrigeration (which is assumed to be unresponsive in the short run) include a short-run price response. For all end uses with simulated equipment choices (including refrigeration), long-run adjustments to the efficiency of the equipment stock can also occur in response to price changes.[5]

Long-run responses to energy prices in the buildings models are determined endogenously through potentially altered equipment choices. Long-run responses occur through the interaction of installed equipment costs, equipment efficiencies, energy prices ("own" prices, and where fuel switching is a possibility, the prices of other energy sources), discount rates, and annual equipment utilization rates.[6]

In the RDM, the equipment cost versus equipment efficiency tradeoffs are modeled by a logistic functional form which provides a continuous adjustment of equipment market shares as prices change. The shares of equipment adjust smoothly from one year to the next in the model unless existing equipment types are removed (because of equipment standards) or new types are introduced (because of technological developments).

In the CDM, equipment shares are determined by comparing annualized capital costs plus operating costs in 1,782 discrete choice "segments." The market segments for equipment are by Census Division (9), building type (11), choice set (there are three choice sets—unrestricted, restricted to the same fuel, and restricted to the same technology), and discount rate (6). Within each of the 1,782 segments, only one piece of equipment is selected. Selections are simulated on the basis of minimizing life-cycle costs among the available alternatives. The 18 combinations of choice sets and discount rates are intended to capture the varied behavior motivating building owners and occupants. The model segmentation also prevents the CDM from necessarily gravitating to a single equipment choice—a situation that would be highly unrealistic in most cases.

As described above, the long-run effects of equipment choice occur over an extended interval, and because of the multi-year equipment lives, the effects persist once purchases are made. Thus, for example, the effects of a temporary price increase, "wear off" over an extended interval. For the RDM, price-induced increases in building shell efficiency (e.g., insulation, caulking, thermally efficient windows) persist longer than equipment purchase decisions, because adjustments to the shell are not retired until the housing unit is retired.[7] Thus, if prices decline in subsequent years, the effects of the installed shell measures will act as a damper on consumption levels, as illustrated below in a simulation that includes a temporary price increase. Equipment purchases other than shell adjustments have a persistence that is less

[3] The RDM simulates insulation upgrades as real energy prices increase.

[4] Among the potential reasons for the generally inelastic short-run price responses of energy consumption are (1) the overall importance of energy-consuming end uses to consumers; (2) limited substitutes, particularly in the short run, when the stock of energy-consuming equipment is fixed; (3) expenditures that generally are a small percentage of household income or business expense, with the possible exception of lower income households; and (4) other market conditions—for example, when payments for rented space include some energy services.

[5] "Minor" fuel projections for the commercial sector are not affected by short-run price elasticities. The minor fuels include residual oil, kerosene, liquefied petroleum gas (LPG), motor gasoline, coal, and renewable energy. In 1997, the minor fuels accounted for 4 percent of commercial delivered energy. For the residential sector, all fuels include a short-run elasticity. Long-run elasticity effects, generated by price-sensitive equipment choices, occur for electricity, natural gas, and distillate fuel oil in both the residential and commercial sectors and for LPG in the residential sector. Results for the dominant energy sources in the buildings sector—electricity, natural gas, and distillate fuel—are examined in this paper.

[6] Equipment that is used only for short periods during the year (e.g., air conditioning in northern climates) will have relatively low energy consumption and thus low energy costs. In such cases, equipment choices will be less influenced by energy prices than they are in areas where equipment is used more heavily.

[7] A 5-percent increase in energy prices is assumed to result in a 1-percent increase in the shell efficiency index for existing residential buildings. No downward adjustment for price declines is made to shell efficiency for existing buildings. Insulation, once in place, is not taken out.

than the life of the structure, and after a price shock they can wear off more rapidly than shell measures. For the equipment-related component of long-run price response there is a 10- to 20-year interval before full adjustment occurs (depending on the end use).

Another aspect of long-run price response is what has been referred to as the efficiency "rebound effect."[8] Efficiency rebound effects occur because the marginal cost of an end-use service is affected by the efficiency of purchased equipment. Higher efficiency equipment lowers the marginal cost of the service (the "price" of the service to the consumer), and the price response is increased consumption. Rebound effects influence consumption in the long run because of their link to equipment efficiency, which only changes gradually as equipment stocks turn over.

Cross-Price Effects

Another type of price effect occurs when one fuel's consumption is affected by changes in another fuel's price. These are referred to as cross-price effects, which can be either short-run or long-run. An example of a short-run cross-price effect would be altering the relative amount of food prepared using electricity relative to that prepared using gas. Although many homes have options to use both fuels (e.g., a home with both a gas oven and an electric microwave oven), short-run fuel switching rarely occurs in the buildings sector, and the buildings models do not include short-run cross-price effects.

Over the long run, the buildings models do exhibit some cross-price responsiveness, because certain equipment choice decisions include the consideration of competing equipment types using different fuels (e.g., electric versus gas water heaters). Thus, some equipment choices are based on more than just the price of a single fuel and result in measurable long-run cross-price elasticities. For example, in choosing residential space heating equipment for new construction, life-cycle costs of various types of equipment (gas furnace, electric resistance, electric heat pump, ground source heat pump) are compared in the model.

Elasticity Estimates and Simulations

To estimate responses to energy price changes, a series of alternate simulations were made with adjustments to the energy price paths from *AEO99*[9] The adjustments begin in the year 2000, and continue through the end of the model run, 2020. Short-run price responses are defined here to be those that occur in the initial year of a price change.[10] Long-run price responses are defined as the percentage change relative to a baseline after 20 years of a persistent change in energy prices.[11] This choice in measuring long-run responses is somewhat arbitrary, and for very long-lived equipment (such as space heaters) some additional responsiveness could potentially occur. Table 1 shows the results of a 10-percent increase in individual energy prices over the *AEO99* levels for all years, one fuel at a time.

The short-run own-price elasticities range from -0.23 to -0.47. Included in the estimated effects are the direct short-run effects plus one year's worth of altered fuel choices and equipment purchases (fuel choice effects were not isolated from equipment purchase effects in the simulations). Long-run own-price effects are larger than short-run own-price effects in both models, as expected.[12] For the commercial sector, however, the long-run elasticity for electricity is only slightly higher than its short-run value.

The relatively small difference between the short-run and long-run price sensitivities for commercial electricity can be understood by isolating "major" end uses from the "minor" end uses. Major end uses—space heating and cooling, water heating, ventilation, cooking, refrigeration, and lighting—have endogenous, price-sensitive usage intensities. Minor end uses—office equipment and other miscellaneous uses[13]—are based on exogenous parameters. Growth in minor end uses is a function of non-price-responsive factors such as

[8]For the commercial model, the same end uses subject to the short-run price elasticity response are also covered by the efficiency rebound effect. For the residential model, space conditioning is covered by the rebound effect. For discussions of the rebound effect, see J.D. Khazzoom, "Economic Implication of Mandated Efficiency Standards for Household Appliances," *Energy Journal*, Vol. 1, No. 4 (1980), pp. 21-40; and J. Henly, H. Ruderman, and M.D. Levine, "Energy Saving Resulting from the Adoption of More Efficient Appliances: A Follow-up," *Energy Journal*, Vol. 9, No. 2 (1988), pp 163-170.

[9]Elasticities herein are computed using the logarithmic formula given by: elasticity = ln(q1 / q0) / ln(p1 / p0), where p0 and q0 are base prices and quantities, and p1 and q1 represent an alternative price-quantity combination. "ln" stands for natural logarithm.

[10]Fuel price changes can also affect capital purchases for retiring equipment in the first year of a simulated price change; however, no attempt has been made to isolate the capital-induced component for the first year.

[11]A 20-year horizon was chosen because NEMS currently runs through 2020 and the initial price increase is imposed in 2000. For equipment such as commercial boilers and residential furnaces, long-run effects could still occur after 2020.

[12]Responsiveness is greater in the long run than in the short run, because all the short-run adaptations are available in the long run, in addition to possible responses of altered equipment stocks.

[13]Examples of other miscellaneous uses include service station equipment, automated teller machines, telecommunications equipment, medical equipment, and elevators and escalators.

Table 1. NEMS *AEO99* Buildings Sector Fuel Price Response Summary

Fuel	Demand Response to Fuel Price Change			
		Long-Run Own-Price and Cross-Price		
	Short-Run Own-Price	Electricity	Gas	Distillate
Residential Sector . .				
Electricity	-0.23	-0.31	0.03	-0.00
Natural Gas	-0.26	0.08	-0.43	0.02
Distillate Fuel	-0.28	0.05	0.15	-0.53
Commercial Sector				
Electricity	-0.24	-0.25	-0.00	0.00
Natural Gas	-0.28	0.00	-0.34	0.03
Distillate Fuel	-0.47	0.00	0.49	-0.87

Note: Own-price elasticities are shown in bold type.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, calculated from the following price path scenarios: Reference Case Price Path, ELAST99.D102298F; Electricity Price Increase Case, ELAST99.D110298B; Natural Gas Price Increase Case, ELAST99.D110298C; Distillate Fuel Price Increase Case, ELAST99.D110298D.

floorspace additions and the increasing penetration of office equipment.[14] The calculated short-run and long-run elasticities for the major end uses are -0.24 and -0.31, respectively.

The spread between long-run and short-run elasticities is wider for residential than for commercial use of natural gas, in part because of the price responsiveness of building shells in the RDM, where opportunities for easy shell upgrades are available for many older housing units. Building shells are assumed not to be price responsive in the commercial sector. Commercial shell improvements generally are options for major building overhauls rather than incremental responses to price. The availability and cost of energy-efficient equipment are also factors, because some end-use efficiency opportunities are greater for the residential sector.[15] For distillate, the CDM is more responsive than the RDM both in the short run and in the long run, because the CDM allows somewhat more price-responsive fuel switching.[16]

Long-run cross-price effects generally are negligible in both models except for the response of distillate consumption to a change in natural gas prices. As gas prices increase, there are some small shifts from gas to distillate. Because projected distillate consumption in 1999 is only about 10 percent of commercial gas consumption and 17 percent of residential gas consumption, any shift from gas to distillate will be magnified by a factor of nearly 6 for residential and just under 10 for commercial. For example, if 10 trillion British thermal units (Btu) of energy consumption shift from gas to distillate, gas consumption in the commercial sector declines by only 0.3 percent, but distillate consumption increases by 2.7 percent (the corresponding changes are 0.2 percent and 1.1 percent for the residential sector). This leveraging of any movement away from gas causes the relatively large cross-price elasticity for distillate in response to gas price changes. For an increase in distillate prices, distillate's small share would cause a much smaller percentage effect on gas—thus the nearly negligible cross-price effects for natural gas in response to changes in distillate prices.

[14]This relatively small difference between the short-run and long-run measured elasticities is due to the exogenous nature of the minor end use projections. The usage intensities and the penetration rates for office equipment and other end uses are based on exogenous analyses and factors that are not price sensitive. For example, computer equipment penetrates into commercial office floorspace at a rate independent of prices. In these simulations, office floorspace growth is also not price sensitive. Finally, computer energy intensity is based on projected adoption and enabling rates of Energy Star equipment and other equipment, which are also not price sensitive. Thus, across the two price scenarios, the base forecasts are the same for minor end uses before applying short-run price elasticity effects. Current-year consumption is adjusted for price effects by using the exogenous projection as the base consumption. This contrasts with the procedures for the major end uses, where both the previous year's base (from which growth occurs) and the current year's consumption are affected by prices. This causes a compounding effect for major end uses, which is not present for minor end uses. The difference causes the exogenously growing minor end uses to have a somewhat smaller and declining measured elasticity than otherwise. This effect does not occur in the RDM, because usage intensities of penetrating end uses are price sensitive, making the base projections a function of price.

[15]For heating and cooling equipment, older residential equipment is relatively less efficient relative to current options than commercial equipment. For example, the installed base efficiency of gas furnaces averages approximately 0.63 in the NEMS model. The efficiency for new furnaces in the residential technology database range from 0.78 high as 0.96. For the commercial sector, boiler efficiencies fall in a tighter range; the installed base is estimated as 0.75 with the range for new boilers from 0.76 to 0.85.

[16]The commercial model structure includes segmentation that allows a greater degree of price-induced fuel switching.

Price Shock Cases

To illustrate the responses of the NEMS buildings models under conditions other than simple, permanent price changes, the *AEO99* reference case can be compared with two cases in which energy prices are doubled relative to the reference case beginning in 2000 for different lengths of time. In one case, prices are permanently doubled. In the other, prices return to the reference case path after a 5-year doubling shock.

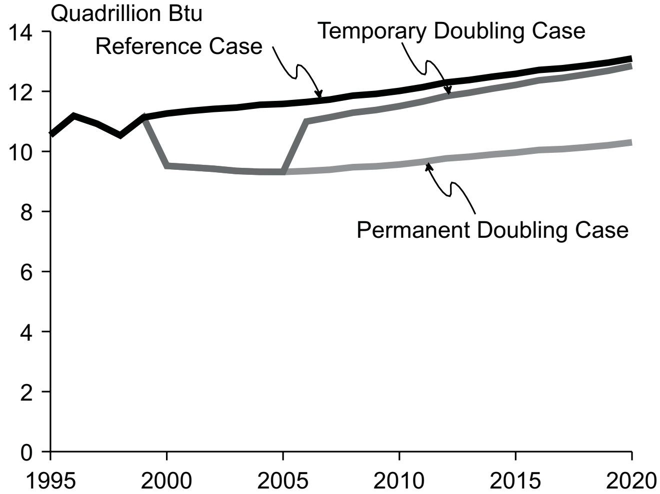
Reviewing the results for the RDM (Figure 1), two effects are notable. First, under persistent doubled prices, there is an initial reduction in energy consumption of approximately 1.8 quadrillion Btu, which gradually widens to 2.8 quadrillion Btu by 2020.[17] The widening gap is attributable to continued choices of higher efficiency equipment under the higher price regime. Its gradual nature is the result of different simulated equipment choices as equipment is retired and then replaced.

The second observation is that, for the case in which prices return to the reference path, there is still a slight gap that narrows over time but does not completely disappear. The gradual narrowing reflects the return to baseline equipment choices after the shock has ended. It is gradual for the same reason that the widening in the permanently price-doubled case is gradual—it occurs as equipment is retired and replaced. Over the 20-year course of the simulation, the gap between the reference case and the price shock still remains, because building shells responded to higher prices during the shock period. Any installed shell efficiency measures remain in place until the buildings themselves are retired from the stock. Similar results are shown for the CDM in Figure 2; however, the effects are not quite as persistent, because in the CDM there is no price-responsive retrofitting of building shells.

Cross Price Effects From Equipment Choices

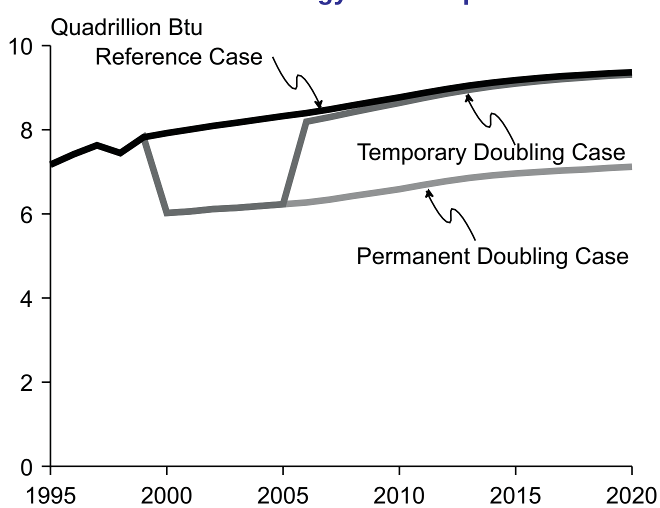
The second set of comparison cases illustrates long-run cross-price effects and uses distillate consumption as the example for both sectors. The comparisons include the reference case and three alternative cases—one with all prices increased by 10 percent, another with only the natural gas price increased by 10 percent, and a third with only the distillate price increased by 10 percent. As for the previous cases, all price increases begin in the year 2000. Comparing these three cases against the

Figure 1. Response to Price-Doubling Sensitivity Cases: Residential Sector Total Delivered Energy Consumption



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, calculated from the following price path scenarios: Reference Case Price Path, ELAST99.D102298F; Permanent Price-Doubling Case, ELAST99.D102798C; Temporary Price-Doubling Case, ELAST99. D102798D.

Figure 2. Response to Price-Doubling Sensitivity Cases: Commercial Sector Total Delivered Energy Consumption



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, calculated from the following price path scenarios: Reference Case Price Path, ELAST99.D102298F; Permanent Price-Doubling Case, ELAST99.D102798C; Temporary Price-Doubling Case, ELAST99. D102798D.

[17] For illustrative purposes, the elasticity effect can be roughly calculated for aggregate residential consumption using an average elasticity of -0.26 (simple mean of three major residential fuels from Table 1, rounded). The effect is the difference between consumption in the base period (q0) and new consumption (q1). Applying the logarithmic formula, q1 = exp(elasticity*ln(p1 / p0) + ln(q0)), where "ln" represents natural logarithm and "exp" is its inverse function. Note that prices affect only about 90 percent of residential energy consumption—minor fuels are modeled without price changes in this simulation. Thus, q0 is approximately 11.3*90% or 10.2. Plugging in values for the residential sector in the year 2000 yields: exp(-0.26*ln(46.6 / 23.3)+ln(10.2))=8.4. The approximate effect is 10.2-8.5, or 1.7 quadrillion Btu, which is very close to the result computed more precisely using individual fuel data.

reference case illustrates the effects of relative prices on fuel choices in the two models.

Figure 3 illustrates the RDM results. When all prices increase, relative energy prices are the same as in the reference case, and fuel switching beyond that already in the reference case is minimized. When only the natural gas price increases, relative energy prices are altered, and equipment using other fuels becomes more attractive relative to natural gas equipment for end uses potentially served by different fuels. The slight increase in the demand for distillate fuel relative to the reference case is the result of the cross-price elasticity effects in the RDM. When only the distillate price increases, the result is a slightly greater suppression of distillate consumption than in the case in which all prices increase, because both the absolute price of distillate fuel and also its price relative to those of other fuels have increased, further suppressing its demand.

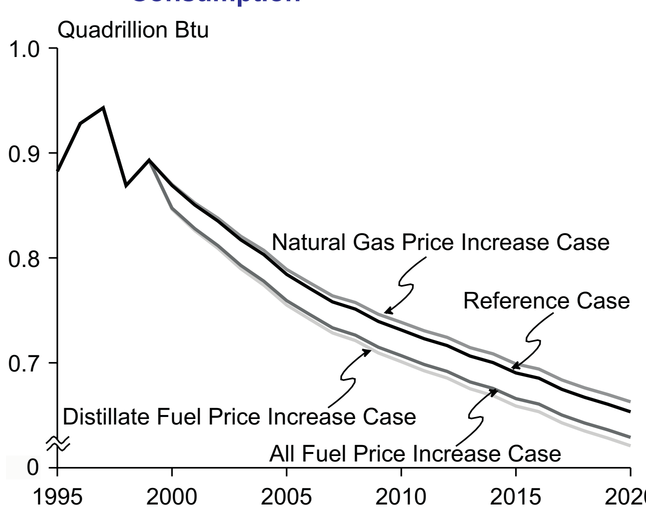
Figure 4 shows the results of a set of parallel cases for the CDM. When all fuel prices increase, demand for distillate is suppressed, as was the case for the RDM. When only the natural gas price increases, however, distillate fuel consumption is projected to be somewhat higher than in the reference case. This represents the switching of commercial gas-fueled services to distillate-fueled services. When only distillate prices increase, a small additional suppression of distillate consumption occurs, similar to that seen for the RDM.

Comparisons With Other Studies

In 1993, the Energy Information Administration commissioned a survey of energy demand elasticities by Professor Carol Dahl,[18] as background for the development of NEMS. The survey incorporated results from previous survey articles as well as from more recent studies (referred to as "new studies" below) that had been performed after the last major surveys. The previous survey articles included data primarily from the 1970s or earlier. A limited number of the new studies included data as recent as 1990, but many of the time-series-based new studies also included pre-energy-crisis intervals, and one used data from 1937 through 1977. Thus, the new studies do not necessarily represent studies of more recent consumer responses to prices.

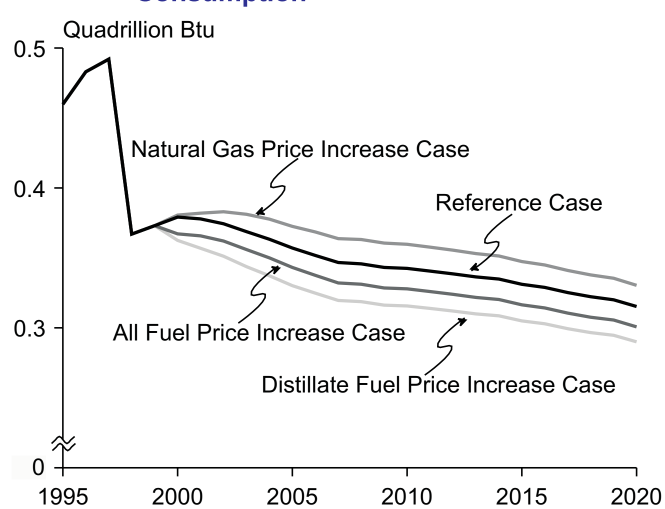
In addition to short-run and long-run elasticities, Dahl also categorized the results of some models as "intermediate run" price elasticities—generally, from studies based on models that did not explicitly recognize a time path of adjustment to prices. Such models usually mix both short-run and long-run effects into a single

Figure 3. Illustration of Cross-Price Effects: Residential Sector Distillate Fuel Consumption



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, calculated from the following price path scenarios: Reference Case Price Path, ELAST99.D102298F; Natural Gas Price Increase Case, ELAST99.D110298C; All Fuel Price Increase Case, ELAST99.D110298E; Distillate Fuel Price Increase Case, ELAST99.D110298D.

Figure 4. Illustration of Cross-Price Effects: Commercial Sector Distillate Fuel Consumption



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, calculated from the following price path scenarios: Reference Case Price Path, ELAST99.D102298F; Natural Gas Price Increase Case, ELAST99.D110298C; All Fuel Price Increase Case, ELAST99.D110298E; Distillate Fuel Price Increase Case, ELAST99.D110298D.

[18] C. Dahl, *A Survey of Energy Demand Elasticities in Support of the Development of the NEMS*, Contract Number DE-AP01-93EI23499 (Washington, DC, October 1993).

estimate—hence the "intermediate run" nomenclature. A few of the studies reported results for the combined residential and commercial sectors, but they are not summarized here because the comparisons to the individual model results are less appropriate. Finally, because the Dahl study focused on own-price elasticities, comparisons here are limited to own-price elasticities.

Table 2 summarizes the information from the Dahl survey for the residential and commercial sectors. The table reports ranges derived from Dahl's extensive tables of individual model results. Table 2 highlights the wide range of estimates that have been made for price responses. For example, residential short-run electricity demand elasticities range from +0.57 to -0.97. For intermediate- and long-run residential electricity demand, the range is from +0.77 to -2.5.

In order to allow comparisons with the NEMS results presented above, the ranges from Table 2 have been aggregated by sector and fuel in Table 3. Furthermore, to make the comparisons more meaningful, the ranges have been narrowed by eliminating models reporting positive own-price elasticities. Also, because details on the scope of the new studies were readily available, only new studies with results that are nationally representative (i.e., not based on regional, State-level, or utility-level data) are included in the Table 3 ranges. National-level studies are the most comparable to the national estimates for NEMS shown in Table 1. Finally, because the intermediate run elasticities generally include effects beyond the initial short-run effects, they were combined with the long-run elasticities from Table 2. Comparing the results from Table 1 with those in Table 3, the NEMS short-run and long-run own-price elasticities fall within the reported overall ranges.

Summary

The behavior of end-use energy consumption under different fuel price paths has been described for the NEMS residential and commercial models. Both short-run and long-run adjustments to prices are included in the models. Responses categorized as short-run represent the immediate behavioral effects of energy price changes on the intensity of utilization of energy-consuming equipment. The long-run elasticities are a function of the cost and performance attributes of available equipment. As the projected equipment availability and cost and efficiency characterizations change, long-run responses to prices also change. The magnitudes of the estimated own-price elasticities for NEMS are consistent with the ranges from a 1993 survey of econometric studies.

Table 2. Summary of Ranges of Residential and Commercial Elasticities from Dahl (1993)

Survey Source	Fuel	Data Type	Model Class	Short Run	Intermediate Run	Long Run
Residential Sector						
Taylor (1977).	Electricity	Grouped	Grouped	-0.07 to -0.61	-0.34 to -1.00	-0.81 to -1.66
	Natural Gas	Aggregate		0.00 to -0.16		0.00 to -3.00
Bohi (1981)	Electricity	Aggregate	Static	-0.08 to -0.45		-0.48 to -1.53
	Electricity	Aggregate	Dynamic	-0.03 to -0.49		-0.44 to -1.89
	Electricity	Aggregate	Structural	-0.16		0.00 to -1.28
	Electricity	Aggregate	Other	-0.18 to -0.54		-0.72 to -2.10
	Electricity	Household	Dynamic	-0.16		-0.45
	Electricity	Household	Static	-0.14		-0.7
	Electricity	Household	Structural	-0.25		-0.66
	Natural Gas	Aggregate	Static			-1.54 to -2.42
	Natural Gas	Aggregate	Dynamic	-0.15 to -0.50		-0.48 to -1.02
	Natural Gas	Aggregate	Structural	-0.30		-2.00
	Natural Gas	Household	Dynamic	-0.28		-0.37
	Natural Gas	Household	Static			-0.17 to -0.45
Bohi & Zimmerman (1984)	Electricity	Aggregate	Static		0.00 to -1.57	-0.18 to -0.52
	Electricity	Aggregate	Dynamic	0.00 to -0.35		-0.26 to -2.50
	Electricity	Household	Structural	-0.20 to -0.76		
	Electricity	Household	Static		-0.55 to -0.71	-0.05 to -0.71
	Electricity	Household	Structural	+0.04 to -0.67		-1.40 to -1.51
	Natural Gas	Aggregate	Dynamic	-0.23 to -0.35		-2.79 to -3.44
	Natural Gas	Aggregate	Dynamic	-0.03 to -0.05		-0.26 to -0.33
	Natural Gas	Household	Static			-0.22 to -0.60
Dahl (1993) Prior Surveys.	Fuel Oil	Grouped	Grouped	0.00 to -0.70		0.00 to -1.50
Dahl (1993) New Studies	Electricity	Aggregate	Grouped	+0.57 to -0.80	-0.11 to -1.11	+0.77 to -2.20
	Electricity	Household	Grouped	-0.02 to -0.97	-0.05 to -0.97	-0.38 to -1.40
	Natural Gas	Aggregate	Grouped	+0.02 to -0.35	1.86 to -2.41	1.56 to -3.44
	Natural Gas	Household	Grouped	-0.63 to -0.88	-0.08 to -1.80	-1.09 to -1.49
	Fuel Oil	Aggregate	Grouped	-0.10 to -0.59	-0.77 to -1.22	-1.85 to -3.5
	Fuel Oil	Household	Grouped	-0.18 to -0.19	-1.09 to -1.56	-0.62 to -0.67
Commercial Sector						
Taylor (1977).	Electricity	Aggregate	Grouped	-0.24 to -0.54		-0.85 to -1.22
	Natural Gas	Aggregate		-0.38		-1.45
Bohi (1981)	Electricity	Aggregate	Dynamic	-0.17 to -1.18		-0.56 to -1.60
	Natural Gas	Disaggregate	Static			-1.04
Bohi & Zimmerman (1984)	Electricity	Disaggregate	Grouped		0.00 to -4.56	0.00 to -1.05
	Natural Gas	Aggregate	Dynamic	0.00 to -0.37		0.00 to -2.27
Dahl (1993) Prior Surveys.	Fuel Oil	Grouped	Grouped	-0.30 to -0.61		-0.55 to -0.70
Dahl (1993) New Studies	Electricity	Aggregate	Grouped	0.00 to -0.82	-0.59 to -0.98	3.36 to -4.74
	Natural Gas	Aggregate	Grouped	-0.16 to -0.37	1.92 to -2.68	0.06 to -2.27
	Fuel Oil	Aggregate	Grouped	-0.07 to -0.19	-0.30	-0.40 to -3.50

Table 3. Summary of Adjusted Overall Buildings Sector Fuel Own-Price Response from Dahl (1993)

Fuel	Short-Run Elasticity	Long-Run Elasticity
Residential Sector		
Electricity	0.00 to -0.80	0.00 to -2.50
Natural Gas	0.00 to -0.88	0.00 to -3.44
Fuel Oil	0.00 to -0.70	0.00 to -3.50
Commercial Sector		
Electricity	-0.17 to -1.18	0.00 to -4.74
Natural Gas	0.00 to -0.38	0.00 to -2.27
Fuel Oil	-0.30 to -0.61	-0.55 to -3.50

Source: C. Dahl, *A Survey of Energy Demand Elasticities in Support of the Development of the NEMS*, Contract Number DE-AP01-93EI23499 (Washington, DC, October 1993). Studies were selected and grouped by the Office of Integrated Analysis and Forecasting.

Annual Energy Outlook Forecast Evaluation

by
Eugene J. Reiser

This paper evaluates the projections in the Annual Energy Outlook *(*AEO*),*[1] *by comparing the projections from the* Annual Energy Outlook 1982 *through the* Annual Energy Outlook 1999 *with actual historical values and providing the rationale for the differences. A set of 16 major consumption, production, imports, price, and economic variables were chosen for evaluation, updating a similar analysis published in the previous edition of* Issues in Midterm Analysis and Forecasting.[2] *This paper expands on the previous one by adding the most recent* AEO *to the evaluation, including 1998 as an additional historical year, and adding a moving average analysis of the projections.*

Introduction

This paper presents an analysis of the forecast record of the *Annual Energy Outlook* (*AEO*). It compares the projections for major energy variables from the reference case for each of the *AEO*s published from April 1983 through December 1998 with actual data.[3] The purpose of the analysis is to provide a measure of the accuracy of the forecasts; however, prediction of future energy markets is not the primary reason for developing and maintaining the models that the Energy Information Administration (EIA) uses to produce the *AEO*. Because the EIA models are developed primarily as tools for policy analysis, a key assumption of the forecasts is that current laws and regulations will remain in effect throughout the forecast horizon. This assumption, while necessary to provide a baseline against which changes in policy can be evaluated, also virtually guarantees that the forecasts will be in error, as laws and regulations pertinent to energy markets change considerably over the years.

The National Energy Modeling System (NEMS)—the current EIA model used to produce the midterm projections in the *AEO*—and the predecessor models were designed to enforce a discipline on the process of energy market analysis by providing a comprehensive set of assumptions that are consistent with our understanding of the factors that affect energy markets—for example, technological innovation, energy service demand growth, and energy resources. The models are modified each year to ensure their relevance to evolving energy issues and to update baseline data, parameters, and assumptions with the most recent historical data. NEMS, first used for the *Annual Energy Outlook 1994* (*AEO94*),[4] was specifically designed for a high level of technological detail and flexibility to address a wide range of policy options.

These models are frequently used in studies conducted for the U.S. Congress, the Department of Energy, and other Government agencies to analyze the impacts of changes in energy policies, regulations, and other major assumptions on future energy supply, demand, and prices, typically using assumptions specified by the client. The most recent examples of analytical studies include an analysis of the Climate Change Technology Initiative[5] and an analysis of the impacts of the Kyoto Protocol[6] at the requests of the Committee on Science of the U.S. House of Representatives; an analysis of the impacts of increased diesel penetration[7] for the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy; an analysis of the Electric System

[1]See Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998), for the most recent *AEO*.

[2]Energy Information Administration, *Issues in Midterm Analysis and Forecasting 1998*, DOE/EIA-0607(98) (Washington, DC, July 1998).

[3]For an analysis of EIA's record for forecasts made from 1977 through 1993, see B. Cohen, G. Peabody, M. Rodekohr, and S. Shaw, "A History of Mid-Term Energy Projections: A Review of the Annual Energy Outlook Projections" (unpublished manuscript, February 1995).

[4]Energy Information Administration, *Annual Energy Outlook 1994*, DOE/EIA-0383(94) (Washington, DC, January 1994).

[5]Energy Information Administration, *Analysis of The Climate Change Technology Initiative*, SR/OIAF/99-01 (Washington, DC, April 1999).

[6]Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03 (Washington, DC, October 1998).

[7]Energy Information Administration, *The Impacts of Increased Diesel Penetration in the Transportation Sector*, SR/OIAF/98-02 (Washington, DC, August 1998).

Public Benefits Protection Act of 1997[8] at the request of Senator James M. Jeffords (R-Vt), Chairman of the Senate Committee on Labor and Human Resources; a study of carbon reduction policies[9] for the U.S. Department of Energy, Office of Policy and International Affairs; a study on the costs and economic impacts of oil imports[10] for the U.S. General Accounting Office; an analysis for Senator Jeffords on open access regulatory changes and their impacts on the electricity industry;[11] and an analysis of carbon mitigation policies[12] prepared for the U.S. Environmental Protection Agency.

Just in the period analyzed in this paper, many legislative actions and policies have been enacted, including the National Appliance and Energy Conservation Act of 1987, the Natural Gas Wellhead Decontrol Act of 1989, the Clean Air Act Amendments of 1990 (CAAA90), the ozone transport rule, the Energy Policy Act of 1992, the repeal of the Power Plant and Industrial Fuel Use Act of 1978 (FUA), the North American Free Trade Agreement, the Omnibus Budget Reconciliation Act of 1993, the Outer Continental Shelf Deep Water Royalty Relief Act of 1995, the Tax Payer Relief Act of 1997, the Climate Change Action Plan developed by the Clinton Administration in 1993 to achieve stabilization of greenhouse gas emissions, various orders issued by the Federal Energy Regulatory Commission (FERC), and various State initiatives for the restructuring of electricity markets. Examples of FERC orders include Order 636, which restructured interstate natural gas pipeline companies and required the separation of sales and transportation functions, and Orders 888 and 889, which provided open access to interstate electricity transmission lines. These actions have had significant impacts on energy supply, demand, and prices, but because of the assumption on current laws and regulations, the impacts were not incorporated in the *AEO* projections until their enactment or effective dates.

In several cases, EIA's models have been used to evaluate some of the potential impacts of these changes in laws and regulations before they were enacted, thus fulfilling EIA's designated role in policy analysis. For example, EIA provided comprehensive analysis to the House Energy and Commerce Committee concerning the impacts of the CAAA90 on the coal and electricity industries. In other cases, the models have been used to analyze policies that were eventually rejected; a prime example is the British thermal unit (Btu) tax proposed in early 1993. Both of these uses of the models illustrate the importance of maintaining a modeling capability apart from the forecasting function, using current laws and regulations as a baseline assumption.

In addition to changes in laws and regulations, a number of other factors can cause energy markets to deviate from the longer term trends represented by the forecasts in the *AEO*. For example, the forecasts assume normal weather patterns; however, the weather will rarely, if ever, be normal in any given year. Although the *AEO* models have not generally been used for analysis of weather conditions on energy markets, temperatures that are colder or warmer than normal for sustained periods have a significant impact on energy consumption. Strikes and political incidents, such as the Iraqi invasion of Kuwait in 1990, are other unanticipated events whose impacts on energy markets are not captured in a mid- to long-term energy projection. Any of these events can cause price volatility and fluctuations in energy consumption and supply. EIA's *Short-Term Energy Outlook* (*STEO*)[13] reflects the impacts of these events and the near-term adjustments to them, and each *AEO* adjusts its near-term forecasts to the most recent *STEO* projections. By presenting quarterly projections and accounting for stock fluctuations and other short-term adjustments, the *STEO* is more applicable to the analysis of such events than is the *AEO*, which presents annual average projections. In order to analyze key uncertainties in energy markets, the *AEO*s have all had various side cases, usually, but not always, including high and low economic growth and high and low world oil price. An analysis of the economic growth cases can be found in the *Issues in Midterm Analysis and Forecasting 1998* and the low world oil price cases in the *Issues in Midterm Analysis and Forecasting 1997*.[14]

Although the primary purpose of the models is policy analysis, many users of the *AEO* view the projections as forecasts. Thus, analyzing the models' performance and the reasons for differences between the projections and

[8]Energy Information Administration, *Analysis of S. 687, the Electric System Public Benefits Protection Act of 1997*, SR/OIAF/98-01 (Washington, DC, February 1998).

[9]Energy Information Administration, *Analysis of Carbon Stabilization Cases*, SR-OIAF/97-01 (Washington, DC, October 1997).

[10]Energy Information Administration, *The Impacts on U.S. Energy Markets and the Economy of Reducing Oil Imports*, SR-OIAF-96-04 (Washington, DC, September 1996).

[11]Energy Information Administration, *An Analysis of FERC's Final Environmental Impact Statement for Electricity Open Access and Recovery of Stranded Costs*, SR-OIAF/96-03 (Washington, DC, September 1996).

[12]Energy Information Administration, *An Analysis of Carbon Mitigation Cases*, SR-OIAF/96-01 (Washington, DC, June 1996).

[13]The Short-Term Integrated Forecasting System (STIFS) provides quarterly forecasts of energy markets for up to 2 years in the future. The most recent projections are provided in Energy Information Administration, *Short-Term Energy Outlook, Second Quarter 1999*, DOE/EIA-0202(99/2Q) (Washington, DC, April 1999). Monthly updates are provided on the EIA web site at www.eia.doe.gov/forecasting_index.html.

[14]Energy Information Administration, *Issues in Midterm Analysis and Forecasting 1997*, DOE/EIA-0607(97) (Washington, DC, July 1997).

history is important both for users and for those responsible for the projections. The models and assumptions used in the *AEO*s undergo continuous evaluation and change, in part because of changes in energy markets and in part as a result of internal assessment of the models' performance. Natural gas markets are an example of both points. The representation of natural gas markets has been revised significantly to reflect deregulation. In addition, the fundamental assumptions about the size and potential growth of natural gas resources have been revised because evaluations of past forecasts have shown that price projections for gas were too high.

This paper presents projections for each *AEO* from 1982 to 1999.[15] The forecast horizon has expanded over the period examined in this paper; for example, the *Annual Energy Outlook 1982* (*AEO82*)[16] projections of energy markets extended only through 1990. Also, although year-by-year forecasts were produced for each *AEO*, many *AEO*s published only selected years. This evaluation includes all projected years, including unpublished projections where available. For some *AEO*s, projection data for the years 1991 to 1994 are not available either in the document or in data files. A set of 16 key energy variables is used in these reports to provide a comprehensive picture of the projections. The projections in this analysis were produced by the models in use at the time. Before 1994, the Intermediate Future Forecasting System was the primary model for midterm projections; however, this evaluation is not meant to assess a specific model but rather to assess the forecasts and the underlying assumptions that shape the results. An evaluation of models is not the purpose of this paper, but we do learn from the forecast evaluations how closely our projections track historical values, and the reviews provide a basis for consideration of changes in the model. NEMS—a longer run model—was first used for the 1994 forecasts, and historical data for comparison are available only for five short-term years. In this case, the best effort is to compare the NEMS results with forecasts from other organizations, as is done in each *AEO*.

Overview

Table 1 provides a summary of the average absolute forecast errors[17] for each of the major variables included in this analysis.[18] The average absolute forecast error is computed as the mean, or average, of all the absolute values of the percentage errors, expressed as percentage differences from actual, shown for each *AEO*, for each year in the forecast, for a given variable. The values in the table are taken from three previous annual evaluations published in *Issues in Midterm Analysis and Forecasting* (*Issues*), and from this paper.

As Table 1 indicates, the forecasts of consumption, production, and economic variables have generally been the most accurate; net import projections have been less accurate; and the price projections[19] have been the least accurate when evaluated on the basis of average absolute percent errors. Year-to-year changes in percent error reflect the addition of new years over time. Most of the percent errors are generally improving over time, with the exception of coal consumption and net coal exports, which seem to reflect the surge in coal consumption by generators in 1996, 1997, and 1998.

For the current *Issues*, found in the last column, each of the consumption, production, and economic variables has been projected with an average absolute percent error of 5.6 percent or less. For both total energy consumption and total electricity sales, the most accurately projected variables during this period, the average absolute percent error is 1.7 percent. Average absolute percent errors for net imports range from 8.8 percent for petroleum to 24.5 percent for coal. For prices, forecasting has proven to be a much greater challenge. Average absolute percent errors for the world oil price, the price of coal to electric utilities, and the average natural gas wellhead price range from 35.9 to 70.2 percent over the period, with natural gas wellhead prices proving to have the highest error of the variables evaluated. Average electricity price projections, however, fared better, with an 11.1-percent average absolute percent error.

The following sections discuss the underlying results in some detail; however, it is clear that quantities are more amenable to the forecasting methods used in the *AEO* than are prices; that the errors in forecasting prices have not, in general, affected the accuracy of projected quantities; and that natural gas has tended to have the highest average forecast error within most categories—consumption, production, and prices. Some of the major

[15]The *AEO*s published in the years 1983 through 1988 were titled as the *Annual Energy Outlook 1982* through the *Annual Energy Outlook 1987*. In 1989, the numbering scheme changed, and that year's report was titled the *Annual Energy Outlook 1989*. Thus, although a forecast has been published annually, there is no *Annual Energy Outlook 1988*.

[16]Energy Information Administration, *Annual Energy Outlook 1982*, DOE/EIA-0383(82) (Washington, DC, April 1983).

[17]The average absolute errors displayed in Table 1 are the average absolute percent errors for each variable shown in Tables 2 through 17.

[18]The forecast evaluation in this paper is only for the *AEO* reference cases. Each *AEO* has provided a range of projections, generally based on different assumptions for world oil prices and economic growth. In many cases, this range of forecasts has, in fact, encompassed the eventual outcome of the variables evaluated. In order to keep the analysis manageable, the focus is on the reference case projections.

[19]All *AEO*s have projected prices in real—inflation-adjusted—dollars. In this paper, all price projections have been converted to nominal dollars, using historical deflators, to facilitate comparison across reports.

Table 1. Comparison of Absolute Percent Errors for *AEO* Forecast Evaluation, From *Issues in Midterm Analysis and Forecasting* 1996 to 1999

Variable	*Issues* 1996 (*AEO82* to *AEO93*)[a]	*Issues* 1997 (*AEO82* to *AEO97*)	*Issues* 1998 (*AEO82* to *AEO98*)	*Issues* 1999 (*AEO82* to *AEO99*)
	Average Absolute Percent Error			
Consumption				
Total Energy Consumption	1.8	1.6	1.7	1.7
Total Petroleum Consumption	3.2	2.8	2.9	2.8
Total Natural Gas Consumption	6.0	5.8	5.7	5.6
Total Coal Consumption	2.9	2.7	3.0	3.2
Total Electricity Sales	1.8	1.6	1.7	1.8
Production				
Crude Oil Production	5.1	4.2	4.3	4.5
Natural Gas Production	5.4	5.0	4.8	4.7
Coal Production	3.8	3.7	3.6	3.6
Imports and Exports				
Net Petroleum Imports	12.0	10.1	9.5	8.8
Net Natural Gas Imports	20.0	17.4	16.7	16.0
Net Coal Exports	17.1	22.1	22.8	24.5
Prices and Economic Variables				
World Oil Prices	82.2	53.1	51.3	56.7
Natural Gas Wellhead Prices	120.4	76.0	72.1	70.2
Coal Prices to Electric Utilities	47.1	34.8	35.3	35.9
Average Electricity Prices	11.0	11.0	11.0	11.1
Gross Domestic Product	5.4	5.0	5.0	5.0

[a]The 1996 *Issues* reflects a comparison for *AEO82* through *AEO93*.

Notes: *AEO* = *Annual Energy Outlook*. The earlier *Issues* reports are: Energy Information Administration, *Issues in Midterm Analysis and Forecasting 1996*, DOE/EIA-0607(96) (Washington, DC, September 1996); *Issues in Midterm Analysis and Forecasting 1997*, DOE/EIA-0607(97) (Washington, DC, July 1997); and *Issues in Midterm Analysis and Forecasting 1998*, DOE/EIA-0607(98) (Washington, DC, July 1998).

Source: Tables 2 through 17.

factors leading to inaccurate forecasts include the assumption in the earlier *AEO*s that the Organization of Petroleum Exporting Countries (OPEC) cartel would maintain the market power and cohesiveness to set world oil prices; the decline of oil production in the former Soviet Union; underestimates of the impact of technology improvements on the production and prices of oil, natural gas, and coal; the impacts of changes in laws and regulations on natural gas prices; the treatment of fuel supply contract provisions for natural gas and coal as fixed and binding; and other events that have caused the actual trends to differ from projected long-term trends, as discussed above.

Energy Consumption

Total Energy Consumption

Total energy consumption forecasts have shown a generally good track record for most of the *AEO* publications.[20] The overall average absolute percent error for the period examined here is 1.7 percent (Table 2), with the largest errors occurring in forecasts for the year 1996 (3.0 percent), and the smallest errors in forecasts for 1991 (0.9 percent).

[20]Prior to 1990, EIA did not collect data on dispersed renewable consumption and production, and the *Annual Energy Outlook 1990* (*AEO90*) was the first *AEO* to include dispersed renewables in the projections. In Table 2, the actual data includes dispersed renewables. Total energy consumption for 1990 and later in *AEO*s prior to the *AEO90* were adjusted to include dispersed renewables to make valid comparisons.

Table 2. Total Energy Consumption: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1998

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	Average Absolute Error
							(Quadrillion Btu)								
AEO82	79.1	79.6	79.9	80.8	82.0	83.3									1.8
AEO83	78.0	79.5	81.0	82.4	83.8	84.6					89.5				1.2
AEO84	78.5	79.4	81.2	83.1	85.0	86.4					93.5				1.6
AEO85	77.6	78.5	79.8	81.2	82.6	83.3	84.2	85.2	85.9	86.7	87.7				1.3
AEO86		77.0	78.8	79.8	80.6	81.5	82.9	84.0	84.8	85.7	86.5	87.9	88.4	88.8	3.2
AEO87			78.9	80.0	81.9	82.8	83.9	85.3	86.4	87.5	88.4				1.5
AEO89				82.2	83.7	84.5	85.4	86.4	87.3	88.2	89.2	90.8	91.4	91.9	1.4
AEO90					84.2	85.4					91.9				0.8
AEO91						84.4	85.0	86.0	87.0	87.9	89.1	90.4	91.8	93.1	1.4
AEO92							84.7	87.0	88.0	89.2	90.5	91.4	92.4	93.4	1.1
AEO93								87.0	88.3	89.8	91.4	92.7	94.0	95.3	0.9
AEO94									88.0	89.5	90.7	91.7	92.7	93.6	1.0
AEO95										89.2	90.0	90.6	91.9	93.0	1.6
AEO96											90.6	91.3	92.5	93.5	1.4
AEO97												92.6	93.6	95.1	1.0
AEO98													94.7	96.7	1.4
AEO99														94.6	0.4
Actual Value	**76.8**	**77.0**	**79.6**	**83.0**	**84.5**	**84.1**	**84.0**	**85.5**	**87.3**	**89.3**	**91.0**	**94.0**	**94.4**	**94.2**	
Average Absolute Error	**1.5**	**1.8**	**0.8**	**1.7**	**1.7**	**1.1**	**0.7**	**0.9**	**0.9**	**1.3**	**1.7**	**2.9**	**2.1**	**1.6**	**1.5**
							(Percent Error)								
AEO82	3.0	3.4	0.4	-2.7	-3.0	-1.0									2.2
AEO83	1.6	3.2	1.8	-0.7	-0.8	0.6					-1.6				1.5
AEO84	2.2	3.1	2.0	0.1	0.6	2.7					2.7				1.9
AEO85	1.1	1.9	0.3	-2.2	-2.2	-1.0	0.2	-0.3	-1.6	-2.9	-3.6				1.6
AEO86		0.0	-1.0	-3.9	-4.6	-3.1	-1.3	-1.7	-2.9	-4.0	-4.9	-6.5	-6.3	-5.8	3.5
AEO87			-0.9	-3.6	-3.1	-1.6	-0.2	-0.2	-1.0	-2.0	-2.9				1.7
AEO89				-1.0	-0.9	0.5	1.6	1.1	0.0	-1.2	-2.0	-3.4	-3.1	-2.5	1.6
AEO90					-0.4	1.5					1.0				1.0
AEO91						0.3	1.1	0.6	-0.4	-1.5	-2.1	-3.8	-2.7	-1.2	1.5
AEO92							0.8	1.8	0.7	-0.1	-0.6	-2.7	-2.1	-0.8	1.2
AEO93								1.8	1.1	0.6	0.4	-1.4	-0.4	1.1	1.0
AEO94									0.8	0.3	-0.3	-2.4	-1.8	-0.7	1.0
AEO95										-0.1	-1.1	-3.6	-2.6	-1.3	1.7
AEO96											-0.4	-2.9	-1.9	-0.8	1.5
AEO97												-1.4	-0.8	1.0	1.1
AEO98													0.3	2.6	1.5
AEO99														0.4	0.4
Average Absolute Percent Error	**2.0**	**2.3**	**1.0**	**2.0**	**2.0**	**1.4**	**0.9**	**1.1**	**1.1**	**1.4**	**1.8**	**3.1**	**2.2**	**1.7**	**1.7**

AEO = Annual Energy Outlook.
Btu = British thermal unit.
Note: Includes nonelectric renewables.
Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-99) (Washington, DC, April 1983 - December 1998).

In terms of the *AEO* publications, the *Annual Energy Outlook 1986*[21] (*AEO86*) had the largest absolute and average absolute percent errors for total energy consumption, at 3.2 quadrillion Btu and 3.5 percent, respectively. There was a significant underestimate of energy consumption for most of the projected years in *AEO86*, in part due to the high fossil fuel prices projected for the publication, which was completed prior to the 1986 collapse in oil prices and published early in 1987. After *AEO86*, there was general improvement in the forecast record, as EIA's experience with lower priced energy markets expanded. It is worth noting, however, that the overall average absolute percent errors for oil price forecasts in *AEO86* were better than in the preceding *AEO*s. Price forecasts for some years in *AEO86* were also better than in some subsequent *AEO*s; for example, some of the subsequent *AEO*s projected world oil prices that were too low for the years 1989 and 1990, and the *Annual Energy*

[21]Energy Information Administration, *Annual Energy Outlook 1986*, DOE/EIA-0383(86) (Washington, DC, February 1987).

Outlook 1991 (*AEO91*)[22] projected much higher prices for 1991 through 1998.

One of the aspects of modeling energy consumption that is important in the evaluation of the forecasts is the effect of regulations such as appliance and automobile efficiency standards. When such standards are incorporated, some decisions that would otherwise be made by the interaction of supply and demand factors are in fact set by fiat, helping to reduce some of the uncertainty associated with the forecasts and reducing at least one source of forecast error.

Total Petroleum Consumption

Total petroleum consumption forecasts have an average absolute percent error of 2.8 percent during the period covered in this evaluation (Table 3). The least accurate forecast year was 1988, for which the *AEO*s averaged about 0.75 million barrels per day lower than the actual consumption of 17.3 million barrels per day. For 1988, the forecasts of the world oil price were also consistently too high, as noted later, with an average absolute percent error of 80.9 percent, the highest error for any year other than 1986, 1995, and 1998. As described in the section on world oil prices, the early *AEO* world oil price projections were influenced by the notion that OPEC could curtail production sufficiently to hold prices up throughout the forecast horizon. This led to extremely high forecasts for 1995 in the early *AEO*s, like the *Annual Energy Outlook 1983* (*AEO83*)[23] and the *Annual Energy Outlook 1984* (*AEO84*),[24] and to the high 1998 forecast compared to the actual price. In addition, the forecasts of economic growth for 1988 tended to be too low in most of the *AEO* publications, which would also lead to an underestimate of demand.

AEO82, the earliest publication considered in this analysis,[25] and *AEO86* had the highest average absolute percent errors for petroleum consumption at 5.3 and 6.1 percent, respectively. Projections of petroleum consumption were underestimated for all years in *AEO86*, which was the last *AEO* completed before the oil price collapse. The projections for the years 1985 through 1987 in *AEO82* were above actual demand; however, the errors for 1988 through 1990 were much smaller and in the opposite direction.

The *AEO82* forecast for the year 1985 had the highest percent error of all the petroleum forecasts evaluated. Residential and commercial consumption was projected to be more than 0.4 million barrels per day higher in 1985 than it actually was, and consumption of petroleum for electricity generation was projected to be more than 1.8 million barrels per day higher in 1985, more than triple the actual value. Both numbers were reduced in *AEO83* and were considerably more accurate. Although the *AEO82* total petroleum consumption projection for 1990 was equal to the historical value at 16.99 million barrels per day, the sectoral projections were not accurate. Residential and commercial demand was projected to be about 0.6 million barrels per day higher, industrial 1.0 million barrels per day higher, transportation 2.5 million barrels per day lower, and electricity generation 1.2 million barrels per day higher than actual. Between *AEO82* and *AEO83*, the role of natural gas had been reevaluated, giving it a larger role in the residential and commercial sectors and, in particular, in the electricity sector. The projections for oil demand in these sectors declined between *AEO82* and *AEO83*, and those for natural gas demand increased.

Following *AEO82*, the projections of residential and commercial oil consumption remained rather close to the actual values, although the slight downturn in 1990 was missed. A general characterization of the forecasts is a tendency to underestimate energy consumption for several years after *AEO84*. At that time, there was an assumption that residential and commercial customers would purchase the most energy-efficient technologies, an assumption that led to overly optimistic expectations of efficiency improvements. The *Annual Energy Outlook 1985* (*AEO85*)[26] shows this impact in the residential and commercial sectors.

In the early forecasts, industrial consumption of oil was overestimated, partially reflecting somewhat optimistic assumptions about the growth of energy-intensive industries but also due to an underestimation of the potential growth of natural gas in an era of high gas prices. Later projections were somewhat underestimated due to assumptions of higher efficiency gains.

Through many of the forecasts, transportation consumption was significantly underestimated. The projected world oil prices were too high; and, in reaction to the higher prices, estimated vehicle efficiency improvements were too high and vehicle miles traveled too low, leading to transportation demand forecasts that were up to 2.5 million barrels per day too low in *AEO82* and frequently up to 1 million barrels per day too low in the next several *AEO*s. These forecasts improved significantly in the *Annual Energy Outlook*

[22]Energy Information Administration, *Annual Energy Outlook 1991*, DOE/EIA-0383(91) (Washington, DC, March 1991).
[23]Energy Information Administration, *Annual Energy Outlook 1983*, DOE/EIA-0383(83) (Washington, DC, May 1984).
[24]Energy Information Administration, *Annual Energy Outlook 1984*, DOE/EIA-0383(84) (Washington, DC, January 1985).
[25]EIA published earlier forecasts in its *Annual Report to Congress*, which are not included in this report.
[26]Energy Information Administration, *Annual Energy Outlook 1985*, DOE/EIA-0383(85) (Washington, DC, February 1986).

Table 3. Total Petroleum Consumption: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1998

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	Average Absolute Error
						(Million Barrels per Day)									
AEO82	18.00	17.89	17.55	17.24	16.98	16.99									0.86
AEO83	15.82	16.13	16.37	16.50	16.56	16.63					17.37				0.40
AEO84	15.77	15.76	16.01	16.27	16.48	16.74					18.00				0.52
AEO85	15.72	15.74	15.97	16.01	16.06	16.08	16.18	16.23	16.32	16.36	16.53				0.86
AEO86		16.07	16.29	16.05	16.07	16.15	16.31	16.37	16.42	16.44	16.46	16.50	16.64	16.80	1.08
AEO87			16.52	16.66	16.96	17.06	17.29	17.56	17.73	17.76	17.72				0.32
AEO89				17.01	17.20	17.44	17.57	17.72	17.76	17.78	17.82	18.05	18.12	18.19	0.39
AEO90					17.24	17.41					18.21				0.33
AEO91						16.95	16.65	16.83	17.01	17.17	17.34	17.53	17.83	18.09	0.40
AEO92							16.74	17.07	17.37	17.59	17.80	17.86	17.99	18.14	0.25
AEO93								17.07	17.45	17.79	18.15	18.26	18.60	18.88	0.15
AEO94									17.67	17.99	18.20	18.42	18.66	18.85	0.25
AEO95										17.53	17.93	17.96	18.29	18.48	0.26
AEO96											17.78	17.88	18.10	18.38	0.33
AEO97												18.18	18.34	18.70	0.14
AEO98													18.89	18.92	0.26
AEO99														18.86	0.18
Actual Value	**15.73**	**16.28**	**16.67**	**17.28**	**17.33**	**16.99**	**16.71**	**17.03**	**17.24**	**17.72**	**17.72**	**18.31**	**18.62**	**18.68**	
Average Absolute Error	**0.60**	**0.61**	**0.51**	**0.75**	**0.64**	**0.37**	**0.41**	**0.42**	**0.47**	**0.44**	**0.41**	**0.49**	**0.54**	**0.44**	**0.49**
						(Percent Error)									
AEO82	14.4	9.9	5.3	-0.2	-2.0	0.0									5.3
AEO83	0.6	-0.9	-1.8	-4.5	-4.4	-2.1					-2.0				2.3
AEO84	0.3	-3.2	-4.0	-5.8	-4.9	-1.5					1.6				3.0
AEO85	-0.1	-3.3	-4.2	-7.3	-7.3	-5.4	-3.2	-4.7	-5.3	-7.7	-6.7				5.0
AEO86		-1.3	-2.3	-7.1	-7.3	-4.9	-2.4	-3.9	-4.8	-7.2	-7.1	-9.9	-10.6	-10.1	6.1
AEO87			-0.9	-3.6	-2.1	0.4	3.5	3.1	2.8	0.2	0.0				1.9
AEO89				-1.6	-0.8	2.6	5.1	4.1	3.0	0.3	0.6	-1.4	-2.7	-2.6	2.3
AEO90					-0.5	2.5					2.8				1.9
AEO91						-0.2	-0.4	-1.2	-1.3	-3.1	-2.1	-4.3	-4.2	-3.2	2.2
AEO92							0.2	0.2	0.8	-0.7	0.5	-2.5	-3.4	-2.9	1.4
AEO93								0.2	1.2	0.4	2.4	-0.3	-0.1	1.1	0.8
AEO94									2.5	1.5	2.7	0.6	0.2	0.9	1.4
AEO95										-1.1	1.2	-1.9	-1.8	-1.1	1.4
AEO96											0.3	-2.3	-2.8	-1.6	1.8
AEO97												-0.7	-1.5	0.1	0.8
AEO98													1.5	1.3	1.4
AEO99														1.0	1.0
Average Absolute Percent Error	**3.8**	**3.7**	**3.1**	**4.3**	**3.7**	**2.2**	**2.5**	**2.5**	**2.7**	**2.5**	**2.3**	**2.7**	**2.9**	**2.3**	**2.8**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-99) (Washington, DC, April 1983 - December 1998).

1987 (*AEO87*),[27] which contained the first set of projections after the oil price collapse in 1986.

Total Natural Gas Consumption

The average absolute percent error for natural gas consumption forecasts for this period is 5.6 percent (Table 4). Projections for 1995 had the highest average absolute percent error at 9.2 percent. For 1995, all the *AEO*s underestimated consumption by anywhere from 1 to 22 percent, primarily due to high natural gas price projections. For many of the statistics presented in this paper, 1995 through 1998 show some of the highest percent errors, because these years have many of the oldest projections, which were made 10 to 12 years earlier. Particularly in the natural gas industry, there were significant changes in energy markets throughout the 1980s. Natural gas price forecasts were very high, as discussed later, and were important causes for the underestimation of consumption in many years in the analysis period, as prices were overstated considerably in comparison with the actual prices.

[27] Energy Information Administration, *Annual Energy Outlook 1987*, DOE/EIA-0383(87) (Washington, DC, March 1988).

Table 4. Total Natural Gas Consumption: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1998

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	Average Absolute Error
						(Trillion Cubic Feet)									
AEO82	15.93	15.72	15.72	16.08	16.59	17.08									1.52
AEO83	17.75	17.63	17.57	17.75	17.76	17.77					16.95				1.31
AEO84	18.22	18.07	18.33	18.61	18.73	18.76					18.75				1.06
AEO85	17.79	17.80	17.89	18.30	18.58	18.71	18.79	18.88	18.82	18.82	18.81				0.94
AEO86		16.52	16.83	17.35	17.27	17.50	17.77	17.77	17.90	18.01	18.04	18.03	18.26	18.34	2.03
AEO87			16.85	16.93	17.24	17.27	17.34	17.43	17.66	18.02	18.31				1.87
AEO89				17.75	17.95	17.94	18.08	18.10	18.34	18.68	18.94	19.17	19.55	19.86	1.60
AEO90					18.34	18.66					20.69				0.47
AEO91						18.53	19.21	19.34	19.56	19.76	20.01	20.21	20.66	20.93	0.80
AEO92							18.79	19.36	19.84	20.08	20.53	20.68	21.12	21.42	0.60
AEO93								20.27	20.17	20.54	20.97	21.54	21.83	22.20	0.44
AEO94									19.87	20.21	20.64	20.99	21.20	21.42	0.62
AEO95										20.82	20.66	20.85	21.21	21.65	0.65
AEO96											21.32	21.64	22.11	22.21	0.41
AEO97												22.15	22.75	23.24	0.97
AEO98													21.84	23.03	0.94
AEO99														21.35	0.06
Actual Value	**17.28**	**16.22**	**17.21**	**18.03**	**18.80**	**18.72**	**19.04**	**19.54**	**20.28**	**20.71**	**21.58**	**21.97**	**21.97**	**21.29**	
Average Absolute Error	**0.82**	**1.13**	**0.73**	**0.73**	**0.99**	**0.70**	**0.77**	**1.01**	**1.26**	**1.30**	**1.99**	**1.43**	**1.10**	**0.99**	**1.13**
						(Percent Error)									
AEO82	-7.8	-3.1	-8.7	-10.8	-11.8	-8.8									8.5
AEO83	2.7	8.7	2.1	-1.6	-5.5	-5.1					-21.5				6.7
AEO84	5.4	11.4	6.5	3.2	-0.4	0.2					-13.1				5.8
AEO85	3.0	9.7	4.0	1.5	-1.2	-0.1	-1.3	-3.4	-7.2	-9.1	-12.8				4.8
AEO86		1.8	-2.2	-3.8	-8.1	-6.5	-6.7	-9.1	-11.7	-13.0	-16.4	-17.9	-16.9	-13.9	9.9
AEO87			-2.1	-6.1	-8.3	-7.7	-8.9	-10.8	-12.9	-13.0	-15.2				9.4
AEO89				-1.6	-4.5	-4.2	-5.0	-7.4	-9.6	-9.8	-12.2	-12.7	-11.0	-6.7	7.7
AEO90					-2.4	-0.3					-4.1				2.3
AEO91						-1.0	0.9	-1.0	-3.6	-4.6	-7.3	-8.0	-6.0	-1.7	3.8
AEO92							-1.3	-0.9	-2.2	-3.0	-4.9	-5.9	-3.9	0.6	2.8
AEO93								3.7	-0.5	-0.8	-2.8	-2.0	-0.6	4.3	2.1
AEO94									-2.0	-2.4	-4.4	-4.5	-3.5	0.6	2.9
AEO95										0.5	-4.3	-5.1	-3.5	1.7	3.0
AEO96											-1.2	-1.5	0.6	4.3	1.9
AEO97												0.8	3.6	9.2	4.5
AEO98													-0.6	8.2	4.4
AEO99														0.3	0.3
Average Absolute Percent Error	**4.7**	**7.0**	**4.3**	**4.1**	**5.3**	**3.8**	**4.0**	**5.2**	**6.2**	**6.3**	**9.2**	**6.5**	**5.0**	**4.7**	**5.6**

AEO = *Annual Energy Outlook*.

Note: *AEO82* projections given in Btu were converted to trillion cubic feet using a conversion factor of 1.03.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-99) (Washington, DC, April 1983 - December 1998).

The FUA also contributed to low estimates of gas consumption by industrial customers. In reaction to a perceived scarcity of natural gas, the FUA legislation attempted to restrict gas use by large electric utility and industrial customers. Because of the number of exemptions granted to electric utilities, however, the FUA had little impact on the forecasts of gas consumption by utilities, except in *AEO82*. The legislation did have some restraining influence on industrial gas consumption forecasts until its repeal in 1987.

With the exceptions of the projections for 1985 through 1988 made in *AEO83* through *AEO85*, natural gas consumption was generally underestimated, concurrent with high price projections. Where consumption was overestimated, the tendency to conservation and the impact of higher prices on demand were not fully captured, even though prices were generally overestimated as well. Before 1995, 1986 was the year with the highest average absolute percent error, at 7.0 percent. Except for *AEO82*, all the errors for 1986 were overestimates.

Although natural gas price projections for 1986 were high, oil price projections were also high, and fuel switching from oil to gas was projected.

Among the *AEO*s, overall average absolute percent errors ranged from 1.9 to 9.9 percent, excepting the *Annual Energy Outlook 1999* (*AEO99*),[28] which included a single estimate of the most recent historical year, with a 0.3-percent error. *AEO86* and *AEO87* had the highest average absolute percent errors, mainly because of underestimates of natural gas use in the industrial sector, although projections for the residential and commercial sectors were also low in the later years. Projections in the 1980s underestimated natural gas consumption for most years, particularly the later years in the horizon, with high price forecasts contributing to the errors. Consumption forecasts improved considerably starting with the *Annual Energy Outlook 1990* (*AEO90*),[29] with average absolute percent errors of 4.5 percent or less. Natural gas price forecasts improved starting with *AEO91*, with average absolute percent errors no more than 22.2 percent.

Total Coal Consumption

The forecasts for coal consumption have been stable and displayed fairly low average errors, largely due to the good record in forecasting electricity sales, for which coal is a major fuel. The average absolute percent error for coal consumption is 3.2 percent (Table 5). As has generally been the case, forecasts for the years 1995 through 1998 tend to have the highest errors, averaging 4.4, 5.0, 5.5, and 4.9 percent, respectively. There was a strong tendency to overestimate in the earlier *AEO*s, particularly *AEO84*, whose forecast for 1995 was 15.4 percent over actual consumption. Factors contributing to the overestimate included a 5.6-percent overestimate for electricity sales, an estimate of efficiency that was about 5 percent too low for coal-fired generating units, and a share for coal in generation that did not account for the eventual greater role of natural gas, particularly among nonutility electricity producers. The shares of coal and natural gas in the industrial sector were similarly affected, with high natural gas price forecasts and an overly optimistic view of the future of metallurgical coal in steelmaking being the primary factors.

Until the later *AEO*s, *AEO84* had the highest average absolute percent error for coal consumption at 5.4 percent, because of the high 1995 projection. Following an increase in natural gas prices in 1996 and 1997, coupled with declining coal prices, there was a drop in gas consumption by electricity generators and a notable surge in coal consumption by generators in 1996 and 1997, which caused some of the larger errors for those years in most *AEO*s. Consequently, the *Annual Energy Outlook 1996* (*AEO96*)[30] and *Annual Energy Outlook 1997* (*AEO97*)[31] have average absolute percent errors of 5.9 and 5.5, respectively.

Total Electricity Sales

Electricity sales have an average absolute percent error of 1.8 over the period studied (Table 6); 1998 is the year with the highest average absolute percent error of 2.7 percent. Electricity sales for all years were overestimated in *AEO82*, and, with the exception of *AEO87*, *AEO85* through *AEO90* tended to underestimate the earlier years and overestimate the later years. In earlier *AEO*s, overestimates tended to occur because of strong growth in electricity demand in the industrial sector resulting from high projections of oil and gas prices and strong growth in consumption in the sector in general. This growth projection was moderated in later forecasts, which incorporated energy efficiency gains and structural shifts in the industrial sector to less energy-intensive industries.

In the forecasts since *AEO91*, electricity sales have been underestimated in most years, primarily as a result of optimistic estimates of efficiency improvements, coupled with continued growth in new uses for electricity, such as new electronic devices (e.g., home security systems, personal computers, and battery chargers) that was not captured in the projections until *AEO97*. In addition, electricity price forecasts have tended to be overstated in most years, largely due to the influence of overstated natural gas and coal prices to electricity producers, as discussed later.

In terms of the *AEO* publications, until *AEO94* the highest average absolute percent error was that of *AEO82*, at 2.7 percent, as the models used in that *AEO* continued to anticipate electricity growth at a pace near that of economic growth, a ratio that has actually been reduced considerably until *AEO94*. The error in electricity sales was more than halved in *AEO83*.

Energy Production

Crude Oil Production

Crude oil production forecasts have an overall average absolute percent error of 4.5 percent over the period evaluated (Table 7). The largest error for any year was

[28]Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998).
[29]Energy Information Administration, *Annual Energy Outlook 1990*, DOE/EIA-0383(90) (Washington, DC, January 1990).
[30]Energy Information Administration, *Annual Energy Outlook 1996*, DOE/EIA-0383(96) (Washington, DC, January 1996).
[31]Energy Information Administration, *Annual Energy Outlook 1997*, DOE/EIA-0383(97) (Washington, DC, December 1996).

Table 5. Total Coal Consumption: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1998

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	Average Absolute Error
							(Million Short Tons)								
AEO82	805	825	843	868	896	936									17
AEO83	807	831	848	870	899	928					1,061				29
AEO84	843	848	866	889	919	958					1,110				49
AEO85	818	833	842	853	867	891	918	943	970	989	1,008				24
AEO86		813	831	860	870	888	919	945	972	995	1,021	1,038	1,051	1,069	27
AEO87			837	837	854	879	896	912	932	954	975				15
AEO89				872	882	894	903	927	947	965	987	990	1,006	1,026	13
AEO90					884	893					984				10
AEO91						893	902	918	932	943	948	962	973	984	24
AEO92							905	934	919	925	934	944	953	961	42
AEO93								929	931	940	947	958	965	970	34
AEO94									920	928	933	938	943	948	54
AEO95										935	940	941	947	948	55
AEO96											937	942	954	962	60
AEO97												948	970	987	56
AEO98													1,009	1,051	17
AEO99														1,040	2
Actual Value	**818**	**804**	**837**	**884**	**890**	**896**	**888**	**908**	**944**	**952**	**962**	**1,006**	**1,029**	**1,038**	
Average Absolute Error	**12**	**26**	**10**	**21**	**17**	**19**	**19**	**22**	**18**	**20**	**42**	**51**	**56**	**51**	**31**
							(Percent Error)								
AEO82	-1.6	2.6	0.7	-1.8	0.7	4.5									2.0
AEO83	-1.3	3.4	1.3	-1.6	1.0	3.6					10.3				3.2
AEO84	3.1	5.5	3.5	0.6	3.3	6.9					15.4				5.4
AEO85	0.0	3.6	0.6	-3.5	-2.6	-0.6	3.4	3.9	2.8	3.9	4.8				2.7
AEO86		1.1	-0.7	-2.7	-2.2	-0.9	3.5	4.1	3.0	4.5	6.1	3.2	2.1	3.0	2.9
AEO87			0.0	-5.3	-4.0	-1.9	0.9	0.4	-1.3	0.2	1.4				1.7
AEO89				-1.4	-0.9	-0.2	1.7	2.1	0.3	1.4	2.6	-1.6	-2.2	-1.2	1.4
AEO90					-0.7	-0.3					2.3				1.1
AEO91						-0.3	1.6	1.1	-1.3	-0.9	-1.5	-4.4	-5.4	-5.2	2.4
AEO92							1.9	2.9	-2.6	-2.8	-2.9	-6.2	-7.4	-7.4	4.3
AEO93								2.3	-1.4	-1.3	-1.6	-4.8	-6.2	-6.6	3.4
AEO94									-2.5	-2.5	-3.0	-6.8	-8.4	-8.7	5.3
AEO95										-1.8	-2.3	-6.5	-8.0	-8.7	5.4
AEO96											-2.6	-6.4	-7.3	-7.3	5.9
AEO97												-5.8	-5.7	-4.9	5.5
AEO98													-1.9	1.3	1.6
AEO99														0.2	0.2
Average Absolute Percent Error	**1.5**	**3.2**	**1.1**	**2.4**	**1.9**	**2.1**	**2.2**	**2.4**	**1.9**	**2.1**	**4.4**	**5.0**	**5.5**	**4.9**	**3.2**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-99) (Washington, DC, April 1983 - December 1998).

1989, with an average absolute percent error of 7.8 percent and all *AEO*s overestimating actual production for that year. Because domestic oil production is assumed to be determined by prices rather than demand, an important input to production forecasts is the world oil price, which has also been overestimated for most years, particularly in the *AEO82* through *AEO85* projections. For 1989, the first four *AEO*s had significantly high world oil price projections, leading to high production forecasts. Following *AEO85*, EIA's price forecasts were either very close to, or significantly under, the actual 1989 price, with a consequent improvement in production projections.

Table 6. Total Electricity Sales: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1998

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	Average Absolute Error
(Billion Kilowatthours)															
AEO82	2,364	2,454	2,534	2,626	2,708	2,811									68
AEO83	2,318	2,395	2,476	2,565	2,650	2,739					3,153				33
AEO84	2,321	2,376	2,461	2,551	2,637	2,738					3,182				35
AEO85	2,317	2,360	2,427	2,491	2,570	2,651	2,730	2,808	2,879	2,949	3,026				36
AEO86		2,363	2,416	2,479	2,533	2,608	2,706	2,798	2,883	2,966	3,048	3,116	3,185	3,255	49
AEO87			2,460	2,494	2,555	2,622	2,683	2,748	2,823	2,902	2,977				52
AEO89				2,556	2,619	2,689	2,760	2,835	2,917	2,994	3,072	3,156	3,236	3,313	52
AEO90					2,612	2,689					3,083				43
AEO91						2,700	2,762	2,806	2,855	2,904	2,959	3,022	3,088	3,151	38
AEO92							2,746	2,845	2,858	2,913	2,975	3,030	3,087	3,146	45
AEO93								2,803	2,840	2,893	2,946	2,998	3,052	3,104	68
AEO94									2,843	2,891	2,928	2,962	3,004	3,039	100
AEO95										2,951	2,967	2,983	3,026	3,058	91
AEO96											2,973	2,998	3,039	3,074	97
AEO97												3,075	3,115	3,168	33
AEO98													3,106	3,204	25
AEO99														3,205	15
Actual Value	**2,324**	**2,369**	**2,457**	**2,578**	**2,647**	**2,713**	**2,762**	**2,763**	**2,861**	**2,935**	**3,013**	**3,098**	**3,140**	**3,220**	
Average Absolute Error	**14**	**27**	**29**	**54**	**53**	**52**	**31**	**47**	**23**	**32**	**66**	**77**	**74**	**87**	**52**
(Percent Error)															
AEO82	1.7	3.6	3.1	1.9	2.3	3.6									2.7
AEO83	-0.3	1.1	0.8	-0.5	0.1	1.0					4.6				1.2
AEO84	-0.1	0.3	0.2	-1.0	-0.4	0.9					5.6				1.2
AEO85	-0.3	-0.4	-1.2	-3.4	-2.9	-2.3	-1.2	1.6	0.6	0.5	0.4				1.3
AEO86		-0.3	-1.7	-3.8	-4.3	-3.9	-2.0	1.3	0.8	1.1	1.2	0.6	1.4	1.1	1.8
AEO87			0.1	-3.3	-3.5	-3.4	-2.9	-0.5	-1.3	-1.1	-1.2				1.9
AEO89				-0.9	-1.1	-0.9	-0.1	2.6	2.0	2.0	2.0	1.9	3.1	2.9	1.7
AEO90					-1.3	-0.9					2.3				1.5
AEO91						-0.5	0.0	1.6	-0.2	-1.1	-1.8	-2.5	-1.7	-2.1	1.3
AEO92							-0.6	3.0	-0.1	-0.7	-1.3	-2.2	-1.7	-2.3	1.5
AEO93								1.4	-0.7	-1.4	-2.2	-3.2	-2.8	-3.6	2.2
AEO94									-0.6	-1.5	-2.8	-4.4	-4.3	-5.6	3.2
AEO95										0.5	-1.5	-3.7	-3.6	-5.0	2.9
AEO96											-1.3	-3.2	-3.2	-4.5	3.1
AEO97												-0.7	-0.8	-1.6	1.1
AEO98													-1.1	-0.5	0.8
AEO99														-0.5	0.5
Average Absolute Percent Error	**0.6**	**1.1**	**1.2**	**2.1**	**2.0**	**1.9**	**1.1**	**1.7**	**0.8**	**1.1**	**2.2**	**2.5**	**2.4**	**2.7**	**1.8**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-99) (Washington, DC, April 1983 - December 1998).

Each of the *AEO*s has had average absolute percent errors for crude oil production of 7.2 percent or lower, with the exception of *AEO83*, which had an average absolute percent error of 10.2 percent. *AEO83* overestimated crude oil production for all years after 1985, with particularly large errors for 1989, 1990, and 1995, the latter of which was 23.6 percent, primarily because of high price forecasts.

Following the oil price collapse of 1986, there were more underestimations than overestimates of crude oil production. As price projections have been reduced over time, the forecasts have captured the impacts of technological improvements in the oil industry, preventing the production forecasts from falling as precipitously as the price projections. The 1998 value in *AEO99* was inaccurate due to the crude oil price collapse as described in that section.

Natural Gas Production

The overall average absolute percent error for natural gas production forecasts is 4.7 percent (Table 8), lower than the 5.6-percent average absolute percent error for natural gas consumption forecasts. Unlike crude oil, most demand for natural gas is met by domestic

Table 7. Crude Oil Production: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1998

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	Average Absolute Error
								(Million Barrels per Day)							
AEO82	8.79	8.85	8.84	8.80	8.66	8.21									0.57
AEO83	8.67	8.71	8.66	8.72	8.80	8.63					8.11				0.75
AEO84	8.86	8.70	8.59	8.45	8.28	8.25					7.19				0.41
AEO85	8.92	8.96	9.01	8.78	8.38	8.05	7.64	7.27	6.89	6.68	6.53				0.32
AEO86		8.80	8.63	8.30	7.90	7.43	6.95	6.60	6.36	6.20	5.99	5.80	5.66	5.54	0.43
AEO87			8.31	8.18	8.00	7.63	7.34	7.09	6.86	6.64	6.54				0.11
AEO89				8.18	7.97	7.64	7.25	6.87	6.59	6.37	6.17	6.05	6.00	5.94	0.30
AEO90					7.67	7.37					6.40				0.08
AEO91						7.23	6.98	7.10	7.11	7.01	6.79	6.48	6.22	5.92	0.23
AEO92							7.37	7.17	6.99	6.89	6.68	6.45	6.28	6.16	0.10
AEO93								7.20	6.94	6.79	6.52	6.22	6.00	5.84	0.20
AEO94									6.87	6.50	6.18	5.92	5.72	5.54	0.42
AEO95										6.58	6.32	6.04	5.74	5.58	0.42
AEO96											6.54	6.33	6.16	5.95	0.18
AEO97												6.47	6.32	6.15	0.08
AEO98													6.41	6.39	0.10
AEO99														6.41	0.17
Actual Value	**8.97**	**8.68**	**8.35**	**8.14**	**7.61**	**7.36**	**7.42**	**7.17**	**6.85**	**6.66**	**6.56**	**6.46**	**6.45**	**6.24**	
Average Absolute Error	**0.16**	**0.12**	**0.34**	**0.35**	**0.59**	**0.50**	**0.24**	**0.16**	**0.17**	**0.19**	**0.34**	**0.27**	**0.40**	**0.35**	**0.31**
								(Percent Error)							
AEO82	-2.0	2.0	5.9	8.1	13.8	11.6									7.2
AEO83	-3.4	0.3	3.7	7.1	15.6	17.3					23.6				10.2
AEO84	-1.2	0.2	2.9	3.8	8.8	12.2					9.6				5.5
AEO85	-0.6	3.2	7.9	7.9	10.1	9.4	3.0	1.4	0.6	0.3	-0.5				4.1
AEO86		1.4	3.4	2.0	3.8	1.0	-6.3	-8.0	-7.1	-6.9	-8.7	-10.2	-12.2	-11.2	6.3
AEO87			-0.5	0.5	5.1	3.7	-1.0	-1.1	0.2	-0.3	-0.3				1.4
AEO89				0.5	4.7	3.9	-2.3	-4.2	-3.8	-4.4	-5.9	-6.3	-7.0	-4.8	4.3
AEO90					0.7	0.2					-2.4				1.1
AEO91						-1.7	-5.9	-1.0	3.8	5.2	3.5	0.3	-3.6	-5.1	3.4
AEO92							-0.6	0.0	2.1	3.4	1.8	-0.2	-2.6	-1.3	1.5
AEO93								0.4	1.4	1.9	-0.6	-3.7	-7.0	-6.4	3.1
AEO94									0.3	-2.4	-5.8	-8.4	-11.3	-11.2	6.6
AEO95										-1.2	-3.7	-6.5	-11.0	-10.6	6.6
AEO96											-0.3	-2.0	-4.5	-4.6	2.9
AEO97												0.2	-2.0	-1.4	1.2
AEO98													-0.6	2.4	1.5
AEO99														2.7	2.7
Average Absolute Percent Error	**1.8**	**1.4**	**4.0**	**4.3**	**7.8**	**6.8**	**3.2**	**2.3**	**2.4**	**2.9**	**5.1**	**4.2**	**6.2**	**5.6**	**4.5**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-99) (Washington, DC, April 1983 - December 1998).

production; thus, natural gas production tends to follow the projections for consumption. Forecasts for 1994 display the highest average absolute percent error, at 6.8 percent, followed by 1995 at 6.5 percent. The highest error for 1995, and for all the production forecasts, occurred in *AEO83*, the first *AEO* to project 1995 production. Despite a very high price forecast, the *AEO83* production projection was about 20 percent below the 1995 actual production, reflecting the low demand projection.

AEO82 underestimated gas production in all years and had an 11.7-percent average absolute percent error, followed by *AEO87* at 7.7 percent; for all the other *AEO*s the average error rate has been 6.8 percent (for *AEO86*) or less. The errors in production forecasts have resulted primarily from the low consumption forecasts, due to high price forecasts. In general, the *AEO*s have understated production, with the exception of the years prior to 1990 in *AEO84* and *AEO85*, and most of the errors have been similar to those for the forecasts of natural gas consumption.

The difficulty of predicting technological improvement in the industry—and, consequently, of predicting the amount of gas that would be available at a given price—led to the high price and low production

Table 8. Natural Gas Production: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1998

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	Average Absolute Error
							(Trillion Cubic Feet)								
AEO82	14.74	14.26	14.33	14.89	15.39	15.88									1.98
AEO83	16.48	16.27	16.20	16.31	16.27	16.29					14.89				1.10
AEO84	17.48	17.10	17.44	17.58	17.52	17.32					16.39				0.90
AEO85	16.95	17.08	17.11	17.29	17.40	17.33	17.32	17.27	17.05	16.80	16.50				0.81
AEO86		16.30	16.27	17.15	16.68	16.90	16.97	16.87	16.93	16.86	16.62	16.40	16.33	16.57	1.26
AEO87			16.21	16.09	16.38	16.32	16.30	16.30	16.44	16.62	16.81				1.38
AEO89				16.71	16.71	16.94	17.01	16.83	17.09	17.35	17.54	17.67	17.98	18.20	0.90
AEO90					16.91	17.25					18.84				0.40
AEO91						17.40	17.48	18.11	18.22	18.15	18.22	18.39	18.82	19.03	0.29
AEO92							17.43	17.69	17.95	18.00	18.29	18.27	18.51	18.75	0.36
AEO93								18.47	18.05	18.16	18.45	18.90	19.07	19.30	0.30
AEO94									17.71	17.68	17.84	18.12	18.25	18.43	0.69
AEO95										18.28	17.98	17.92	18.21	18.63	0.61
AEO96											18.90	19.15	19.52	19.59	0.47
AEO97												19.10	19.70	20.17	0.77
AEO98													18.85	19.06	0.07
AEO99														18.80	0.18
Actual Value	**16.45**	**16.06**	**16.62**	**17.10**	**17.31**	**17.81**	**17.70**	**17.84**	**18.10**	**18.82**	**18.60**	**18.79**	**18.90**	**18.98**	
Average Absolute Error	**0.82**	**0.86**	**0.80**	**0.73**	**0.73**	**0.96**	**0.62**	**0.73**	**0.70**	**1.28**	**1.20**	**0.75**	**0.69**	**0.61**	**0.84**
							(Percent Error)								
AEO82	-10.4	-11.2	-13.8	-12.9	-11.1	-10.8									11.7
AEO83	0.2	1.3	-2.5	-4.6	-6.0	-8.5					-19.9				6.2
AEO84	6.3	6.5	4.9	2.8	1.2	-2.8					-11.9				5.2
AEO85	3.0	6.4	2.9	1.1	0.5	-2.7	-2.1	-3.2	-5.8	-10.7	-11.3				4.5
AEO86		1.5	-2.1	0.3	-3.6	-5.1	-4.1	-5.4	-6.5	-10.4	-10.6	-12.7	-13.6	-12.7	6.8
AEO87			-2.5	-5.9	-5.4	-8.4	-7.9	-8.6	-9.2	-11.7	-9.6				7.7
AEO89				-2.3	-3.5	-4.9	-3.9	-5.7	-5.6	-7.8	-5.7	-6.0	-4.9	-4.1	4.9
AEO90					-2.3	-3.1					1.3				2.2
AEO91						-2.3	-1.2	1.5	0.7	-3.6	-2.0	-2.1	-0.4	0.3	1.6
AEO92							-1.5	-0.8	-0.8	-4.4	-1.7	-2.8	-2.1	-1.2	1.9
AEO93								3.5	-0.3	-3.5	-0.8	0.6	0.9	1.7	1.6
AEO94									-2.2	-6.1	-4.1	-3.6	-3.4	-2.9	3.7
AEO95										-2.9	-3.3	-4.6	-3.7	-1.8	3.3
AEO96											1.6	1.9	3.3	3.2	2.5
AEO97												1.6	4.2	6.3	4.1
AEO98													-0.3	0.4	0.3
AEO99														-0.9	0.9
Average Absolute Percent Error	**5.0**	**5.4**	**4.8**	**4.3**	**4.2**	**5.4**	**3.5**	**4.1**	**3.9**	**6.8**	**6.5**	**4.0**	**3.7**	**3.2**	**4.7**

AEO = *Annual Energy Outlook*.

Note: *AEO82* projections given in Btu were converted to trillion cubic feet using a conversion factor of 1.03.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-99) (Washington, DC, April 1983 - December 1998).

forecasts in the earlier *AEO*s. Following the gas shortages of the late 1970s and the low resource estimates by most geologists, the conventional wisdom of the early to mid-1980s was that natural gas was a scarce resource. This perception changed as the impact of price controls that had curtailed production began to diminish. Also, beginning in the mid-1980s, a number of technological advances, such as directional drilling, 3-D seismic imaging, and slim-hole drilling, lowered the cost of gas exploration and production and expanded the estimates of the resource base. Beginning with *AEO90*, the forecasts of both production and price improved.

Coal Production

Similar to coal consumption, coal production forecasts have an overall average absolute percent error of 3.6 percent (Table 9). Like those for natural gas, the forecasts for coal production have generally followed the consumption forecasts, with electricity sales being the dominant factor. However, an additional input is the level of coal exports, which also affects coal production significantly. Where coal production has been overestimated, a large part of the reason has been an overstating of the level of

Table 9. Coal Production: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1998

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	Average Absolute Error
						(Million Short Tons)									
AEO82	914	939	963	995	1,031	1,080									45
AEO83	900	926	947	974	1,010	1,045					1,191				44
AEO84	899	921	948	974	1,010	1,057					1,221				49
AEO85	886	909	930	940	958	985	1,015	1,041	1,072	1,094	1,116				40
AEO86		890	920	954	962	983	1,017	1,044	1,073	1,097	1,126	1,142	1,156	1,176	48
AEO87			917	914	932	962	978	996	1,020	1,043	1,068				33
AEO89				941	946	977	990	1,018	1,039	1,058	1,082	1,084	1,107	1,130	31
AEO90					973	987					1,085				34
AEO91						1,035	1,002	1,016	1,031	1,043	1,054	1,065	1,079	1,096	20
AEO92							1,004	1,040	1,019	1,034	1,052	1,064	1,074	1,087	24
AEO93								1,039	1,043	1,054	1,065	1,076	1,086	1,094	33
AEO94									999	1,021	1,041	1,051	1,056	1,066	29
AEO95										1,006	1,010	1,011	1,016	1,017	56
AEO96											1,037	1,044	1,041	1,045	37
AEO97												1,028	1,052	1,072	40
AEO98													1,088	1,122	3
AEO99														1,125	6
Actual Value	**884**	**890**	**919**	**950**	**981**	**1,029**	**996**	**998**	**945**	**1,034**	**1,033**	**1,064**	**1,090**	**1,119**	
Average Absolute Error.	**16**	**27**	**19**	**22**	**30**	**39**	**13**	**30**	**92**	**25**	**59**	**26**	**31**	**39**	**36**
						(Percent Error)									
AEO82	3.4	5.5	4.8	4.7	5.1	5.0									4.7
AEO83	1.8	4.0	3.0	2.5	3.0	1.6					15.3				4.5
AEO84	1.7	3.5	3.2	2.5	3.0	2.7					18.2				5.0
AEO85	0.2	2.1	1.2	-1.1	-2.3	-4.3	1.9	4.3	13.4	5.8	8.0				4.1
AEO86		0.0	0.1	0.4	-1.9	-4.5	2.1	4.6	13.5	6.1	9.0	7.3	6.1	5.1	4.7
AEO87			-0.2	-3.8	-5.0	-6.5	-1.8	-0.2	7.9	0.9	3.4				3.3
AEO89				-0.9	-3.6	-5.1	-0.6	2.0	9.9	2.3	4.7	1.9	1.6	1.0	3.1
AEO90					-0.8	-4.1					5.0				3.3
AEO91						0.6	0.6	1.8	9.1	0.9	2.0	0.1	-1.0	-2.1	2.0
AEO92							0.8	4.2	7.8	0.0	1.8	0.0	-1.5	-2.9	2.4
AEO93								4.1	10.4	1.9	3.1	1.1	-0.4	-2.2	3.3
AEO94									5.7	-1.3	0.8	-1.2	-3.1	-4.7	2.8
AEO95										-2.7	-2.2	-5.0	-6.8	-9.1	5.2
AEO96											0.4	-1.9	-4.5	-6.6	3.3
AEO97												-3.4	-3.5	-4.2	3.7
AEO98													-0.2	0.3	0.2
AEO99														0.5	0.5
Average Absolute Percent Error	**1.8**	**3.0**	**2.1**	**2.3**	**3.1**	**3.8**	**1.3**	**3.0**	**9.7**	**2.4**	**5.7**	**2.4**	**2.9**	**3.5**	**3.6**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-99) (Washington, DC, April 1983 - December 1998).

coal exports, especially for the years 1993 through 1998, as discussed below.

The highest average absolute percent error for coal production is 9.7 percent for 1993, when there was a strike by coal miners that sharply curtailed production. All *AEO*s produced before the strike show high forecast errors for 1993. The second highest average absolute percent error is for 1995, at 5.7 percent. The forecasts for 1995 in *AEO83* through *AEO86* range from 8.0 to 18.2 percent above the actual 1995 level, although later forecasts show errors of 5 percent or less. This reflects the overestimation of coal consumption, particularly in *AEO83* and *AEO84*, and the higher-than-realized coal export forecasts in *AEO83* through *AEO86* (see below). The forecasts for other years average much closer to the actual values, with average absolute percent errors ranging from 1.3 to 3.8 percent. The *AEO* publications display little variation in their overall average errors, with the *Annual Energy Outlook 1995* (*AEO95*)[32] showing the highest average absolute percent error of 5.2 percent, mainly because of its severe underestimates for 1996 through 1998, which was due to the surge in coal consumption by electricity generation for those years.

[32]Energy Information Administration, *Annual Energy Outlook 1995*, DOE/EIA-0383(95) (Washington, DC, January 1995).

Energy Imports and Exports

While the United States is a major importer of petroleum, it also imports natural gas, although in much smaller quantities. Coal is the only fuel for which the United States is a net exporter.

Net Petroleum Imports

Because domestic production of petroleum is insufficient to meet demand, imports make up the difference between demand and supply.[33] The average absolute percent error for net petroleum imports over the period studied was 8.8 percent (Table 10). The forecast year with the highest average absolute percent error proved to be 1985, for which the *AEO*s averaged a 28.1-percent error; subsequent years showed considerable improvement. In general, there was a tendency to underestimate imports for the mid-1980s, because of underestimates of consumption and overestimates of production. Except for *AEO83* and *AEO85*, this tendency was generally

Table 10. Net Petroleum Imports: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1998

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	Average Absolute Error
							(Million Barrels per Day)								
AEO82	7.58	7.45	7.12	6.82	6.66	7.09									1.23
AEO83	5.15	5.44	5.73	5.79	5.72	5.95					6.96				0.78
AEO84	4.85	5.11	5.53	5.95	6.31	6.59					8.65				0.59
AEO85	4.17	4.38	4.73	4.93	5.36	5.72	6.23	6.66	7.14	7.39	7.74				0.84
AEO86		5.15	5.38	5.46	5.92	6.46	7.09	7.50	7.78	7.96	8.20	8.47	8.74	9.04	0.49
AEO87			5.81	6.04	6.81	7.28	7.82	8.34	8.71	8.94	8.98				0.76
AEO89				6.28	6.84	7.49	7.96	8.53	8.83	9.04	9.28	9.60	9.64	9.75	0.85
AEO90					7.20	7.61					9.13				0.56
AEO91						7.28	7.25	7.34	7.48	7.72	8.10	8.57	9.09	9.61	0.24
AEO92							6.86	7.42	7.88	8.16	8.55	8.80	9.06	9.32	0.28
AEO93								7.25	8.01	8.49	9.06	9.38	9.92	10.29	0.68
AEO94									8.04	8.77	9.21	9.60	10.02	10.24	0.87
AEO95										8.09	8.65	8.99	9.56	9.89	0.43
AEO96											8.25	8.51	8.82	9.31	0.21
AEO97												8.49	8.89	9.58	0.14
AEO98													9.05	9.29	0.14
AEO99														9.26	0.19
Actual Value	**4.29**	**5.44**	**5.91**	**6.59**	**7.20**	**7.16**	**6.63**	**6.94**	**7.62**	**8.05**	**7.89**	**8.50**	**9.16**	**9.45**	
Average Absolute Error	**1.21**	**0.74**	**0.60**	**0.76**	**0.85**	**0.56**	**0.71**	**0.72**	**0.52**	**0.47**	**0.80**	**0.44**	**0.38**	**0.34**	**0.61**
							(Percent Error)								
AEO82	76.7	36.9	20.5	3.5	-7.5	-1.0									24.3
AEO83	20.0	0.0	-3.0	-12.1	-20.6	-16.9					-11.8				12.1
AEO84	13.1	-6.1	-6.4	-9.7	-12.4	-8.0					9.6				9.3
AEO85	-2.8	-19.5	-20.0	-25.2	-25.6	-20.1	-6.0	-4.0	-6.3	-8.2	-1.9				12.7
AEO86		-5.3	-9.0	-17.1	-17.8	-9.8	6.9	8.1	2.1	-1.1	3.9	-0.4	-4.6	-4.3	7.0
AEO87			-1.7	-8.3	-5.4	1.7	17.9	20.2	14.3	11.1	13.8				10.5
AEO89				-4.7	-5.0	4.6	20.1	22.9	15.9	12.3	17.6	12.9	5.2	3.2	11.3
AEO90					0.0	6.3					15.7				7.3
AEO91						1.7	9.4	5.8	-1.8	-4.1	2.7	0.8	-0.8	1.7	3.2
AEO92							3.5	6.9	3.4	1.4	8.4	3.5	-1.1	-1.4	3.7
AEO93								4.5	5.1	5.5	14.8	10.4	8.3	8.9	8.2
AEO94									5.5	8.9	16.7	12.9	9.4	8.4	10.3
AEO95										0.5	9.6	5.8	4.4	4.7	5.0
AEO96											4.6	0.1	-3.7	-1.5	2.5
AEO97												-0.1	-2.9	1.4	1.5
AEO98													-1.2	-1.7	1.4
AEO99														-2.0	2.0
Average Absolute Percent Error	**28.1**	**13.6**	**10.1**	**11.5**	**11.8**	**7.8**	**10.6**	**10.3**	**6.8**	**5.9**	**10.1**	**5.2**	**4.2**	**3.5**	**8.8**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-99) (Washington, DC, April 1983 - December 1998).

[33] Stocks may also contribute but are assumed to be stable over the long term and have not been specifically projected in the *AEO* forecasts.

reversed in projections of the 1990s, with significant overestimates of net petroleum imports for many years in *AEO84* through *AEO95*. Although in some *AEO*s this corresponded to overestimates of consumption and/or underestimates of production, it was also exacerbated by the contribution of inaccurate forecasts for other sources of supply, such as natural gas liquids and processing gain, the treatment of stocks, and assumptions about the pace of acquisition of crude oil for the Strategic Petroleum Reserve.

By publication, the *AEO*s for 1982 through 1985, 1987, 1989, and 1994 proved to have the highest average absolute percent errors for forecasts of net petroleum imports. *AEO82* strongly overestimated imports for 1985 through 1987; however, its forecasts for the subsequent years were markedly better. Because high estimates of oil prices led to high production forecasts, *AEO83*, *AEO84*, and *AEO85* strongly underestimated imports in many years, as did *AEO86* for the late 1980s. Later reports tended to overestimate imports due to underestimates of production.

Net Natural Gas Imports

Net natural gas imports play a small, but increasingly important role in meeting natural gas demand, largely due to the growth of natural gas imports from Canada, which have risen steadily from 4 percent of natural gas supply in 1984 to more than 13 percent in 1998. The overall average absolute percent error for the period covered in this study is 16.0 percent, with the largest average absolute percent error for the year 1986 at 49.2 percent (Table 11). All the forecasts for 1986 were overstated, with errors as high as 72.7 percent (*AEO82*). There was a substantial oil price collapse in 1986, and petroleum imports displaced other energy sources, such as Canadian gas, for much of the Nation's consumption needs, especially in the industrial and electricity generation sectors. Forecasts for 1987 were overstated in the first four *AEO*s, but *AEO86* and *AEO87* reversed the pattern with underestimates. *AEO85* also showed high overestimates through 1992 and underestimates for later years. Most *AEO*s tended to underestimate imports, with errors as high as 54.2 percent for 1995 in *AEO83*.

The major determining factors of natural gas imports have been the economics of natural gas trade with Canada, the assumptions of pipeline capacity from Canada, the assessment of liquefied natural gas imports from Algeria, and prospects for trade with Mexico and Japan. The tendency was for net gas imports to be overstated for the first four *AEO*s, except for the 1989, 1990, and 1993 through 1995 forecasts. Since the *AEO86* forecast, there has been a greater tendency to underestimate gas imports. Since the *Annual Energy Outlook 1993* (*AEO93*),[34] the projections have been much closer to the actual values, with average absolute percent errors of 5.8 percent or less, although the *AEO99* projection for 1998 reflects an historical update.

Net Coal Exports

The absolute percent errors in projections for net coal exports have averaged 24.5 percent over the period of this study (Table 12). The forecast year 1994 had the highest average absolute percent error at 48.1 percent, followed by 1998 at 40.8 percent. All the *AEO*s except *AEO95* overstated 1994 coal exports by anywhere from about 30 percent to 77 percent. For *AEO84* through *AEO94*, coal exports were generally underestimated through 1992 and overestimated in later years. Except for 1998, *AEO95* and *AEO96* generally underestimated exports by a range of 8 percent to 19 percent.

AEO82 overestimated future coal exports with an average absolute percent error of 37.5 percent, due largely to the assumption that U.S. coal exports would garner an ever-increasing share of world coal trade, which was also expected to grow in reaction to high world oil prices. *AEO83*, in contrast, had a much more realistic view of future coal exports and, with the exception of 1995, had much smaller errors. *AEO83*, *AEO90*, and *AEO95* through *AEO99* were the closest of all the *AEO*s with respect to projected coal exports. Projections for 1993 through 1998 in *AEO91* through *AEO94* were far too high, in part because of the 1993 coal miners' strike that reduced this country's competitive position in world coal markets. In addition, world coal trade has not grown as much as previously assumed, because European consumers have turned increasingly to natural gas for industry and power generation, and environmental concerns have led some countries to reduce coal consumption as a means of reducing carbon emissions. *AEO95* and *AEO96* appear to be overcompensating for this trend. *AEO99* partially reflects historical data for 1998.

[34]Energy Information Administration, *Annual Energy Outlook 1993*, DOE/EIA-0383(93) (Washington, DC, January 1993).

Table 11. Net Natural Gas Imports: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1998

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	Average Absolute Error
						(Trillion Cubic Feet)									
AEO82	1.19	1.19	1.19	1.19	1.19	1.19									0.24
AEO83	1.08	1.16	1.23	1.23	1.23	1.23					1.23				0.38
AEO84	0.99	1.05	1.16	1.27	1.43	1.57					2.11				0.23
AEO85	0.94	1.00	1.19	1.45	1.58	1.86	1.94	2.06	2.17	2.32	2.44				0.22
AEO86		0.74	0.88	0.62	1.03	1.05	1.27	1.39	1.47	1.66	1.79	1.96	2.17	2.38	0.52
AEO87			0.84	0.89	1.07	1.16	1.26	1.36	1.46	1.65	1.75				0.49
AEO89				1.15	1.32	1.44	1.52	1.61	1.70	1.79	1.87	1.98	2.06	2.15	0.45
AEO90					1.26	1.43					2.07				0.22
AEO91						1.36	1.53	1.70	1.82	2.11	2.30	2.33	2.36	2.42	0.34
AEO92							1.48	1.62	1.88	2.08	2.25	2.41	2.56	2.68	0.32
AEO93								1.79	2.08	2.35	2.49	2.61	2.74	2.89	0.13
AEO94									2.02	2.40	2.66	2.74	2.81	2.85	0.08
AEO95										2.46	2.54	2.80	2.87	2.87	0.06
AEO96											2.56	2.75	2.85	2.88	0.07
AEO97												2.82	2.96	3.16	0.12
AEO98													2.95	3.19	0.17
AEO99														2.92	0.05
Actual Value	**0.89**	**0.69**	**0.94**	**1.22**	**1.28**	**1.45**	**1.64**	**1.92**	**2.21**	**2.46**	**2.69**	**2.79**	**2.83**	**2.97**	
Average Absolute Error	**0.16**	**0.34**	**0.20**	**0.19**	**0.14**	**0.20**	**0.24**	**0.31**	**0.39**	**0.37**	**0.53**	**0.31**	**0.26**	**0.28**	**0.30**
						(Percent Error)									
AEO82	33.1	72.7	26.7	-2.5	-7.0	-17.7									26.6
AEO83	20.8	68.4	31.0	0.8	-3.9	-14.9					-54.2				27.7
AEO84	10.7	52.4	23.5	4.1	11.7	8.6					-21.5				18.9
AEO85	5.1	45.1	26.7	18.9	23.4	28.6	18.0	7.2	-1.8	-5.8	-9.2				17.3
AEO86		7.4	-6.3	-49.2	-19.5	-27.4	-22.7	-27.6	-33.5	-32.6	-33.4	-29.7	-23.3	-19.9	25.6
AEO87			-10.5	-27.0	-16.4	-19.8	-23.4	-29.2	-33.9	-33.0	-34.9				25.3
AEO89				-5.7	3.1	-0.4	-7.5	-16.2	-23.1	-27.3	-30.4	-29.0	-27.2	-27.6	18.0
AEO90					-1.6	-1.1					-23.0				8.5
AEO91						-5.9	-6.9	-11.5	-17.6	-14.3	-14.4	-16.5	-16.6	-18.5	13.6
AEO92							-10.0	-15.7	-14.9	-15.5	-16.3	-13.6	-9.5	-9.8	13.2
AEO93								-6.8	-5.9	-4.5	-7.3	-6.5	-3.2	-2.7	5.3
AEO94									-8.6	-2.5	-1.0	-1.8	-0.7	-4.0	3.1
AEO95										-0.1	-5.5	0.4	1.4	-3.4	2.1
AEO96											-4.7	-1.4	0.7	-3.0	2.5
AEO97												1.1	4.6	6.4	4.0
AEO98													4.2	7.4	5.8
AEO99														-1.7	1.7
Average Absolute Percent Error	**17.4**	**49.2**	**20.8**	**15.5**	**10.8**	**13.8**	**14.8**	**16.3**	**17.4**	**15.1**	**19.7**	**11.1**	**9.2**	**9.5**	**16.0**

AEO = Annual Energy Outlook.

Note: *AEO82* projections given in Btu were converted to trillion cubic feet using a conversion factor of 1.03.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-99) (Washington, DC, April 1983 - December 1998).

Energy Prices and Economic Growth[35]

World Oil Prices

World oil prices have the second highest average absolute percent errors of all the variables evaluated in this paper, with natural gas prices at the wellhead having the highest. Overall, the average absolute percent error for world oil price forecasts has been 56.7 percent (Table 13). However, the earlier *AEO*s had a much higher average absolute percent error, and the publications after *AEO86* show considerable improvement, with the exception of *AEO91*, which was affected by the Iraqi invasion of Kuwait. *AEO91*, prepared during the short-term escalation of oil prices caused by the invasion, projected

[35]Forecasts of energy prices and the gross national or gross domestic product (GDP) have been converted to nominal terms by using the historical gross domestic product deflators.

Table 12. Net Coal Exports: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1998

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	Average Absolute Error
						(Million Short Tons)									
AEO82	109	114	120	127	135	144									34
AEO83	83	86	90	94	99	105					116				9
AEO84	72	74	77	81	86	91					106				13
AEO85	83	83	83	84	85	87	89	92	95	98	102				14
AEO86		87	87	88	89	91	92	94	96	98	100	101	102	103	17
AEO87			76	72	73	76	77	79	82	83	86				18
AEO89				84	80	82	83	85	87	88	90	93	97	99	18
AEO90					95	92					99				11
AEO91						105	96	96	97	100	104	100	104	111	21
AEO92							98	99	103	109	116	117	120	124	32
AEO93								108	111	113	117	118	120	124	39
AEO94									79	93	108	110	113	117	30
AEO95										57	66	69	70	70	9
AEO96											71	76	77	77	7
AEO97												82	84	86	9
AEO98													80	83	9
AEO99														75	6
Actual Value	**91**	**83**	**78**	**93**	**98**	**103**	**106**	**99**	**67**	**64**	**81**	**83**	**76**	**69**	
Average Absolute Error	**13**	**9**	**12**	**13**	**15**	**16**	**17**	**8**	**27**	**31**	**21**	**18**	**22**	**28**	**19**
						(Percent Error)									
AEO82	19.8	37.3	53.8	36.6	37.8	39.8									37.5
AEO83	-8.8	3.6	15.4	1.1	1.0	1.9					43.2				10.7
AEO84	-20.9	-10.8	-1.3	-12.9	-12.2	-11.7					30.9				14.4
AEO85	-8.8	0.0	6.4	-9.7	-13.3	-15.5	-16.0	-7.1	41.8	53.1	25.9				18.0
AEO86		4.8	11.5	-5.4	-9.2	-11.7	-13.2	-5.1	43.3	53.1	23.5	21.7	34.2	49.3	22.0
AEO87			-2.6	-22.6	-25.5	-26.2	-27.4	-20.2	22.4	29.7	6.2				20.3
AEO89				-9.7	-18.4	-20.4	-21.7	-14.1	29.9	37.5	11.1	12.0	27.6	43.5	22.4
AEO90					-3.1	-10.7					22.2				12.0
AEO91						1.9	-9.4	-3.0	44.8	56.3	28.4	20.5	36.8	60.9	29.1
AEO92							-7.5	0.0	53.7	70.3	43.2	41.0	57.9	79.7	44.2
AEO93								9.1	65.7	76.6	44.4	42.2	57.9	79.7	53.6
AEO94									17.9	45.3	33.3	32.5	48.7	69.6	41.2
AEO95										-10.9	-18.5	-16.9	-7.9	1.4	11.1
AEO96											-12.3	-8.4	1.3	11.6	8.4
AEO97												-1.2	10.5	24.6	12.1
AEO98													5.3	20.3	12.8
AEO99														8.7	8.7
Average Absolute Percent Error	**14.6**	**11.3**	**15.2**	**14.0**	**15.1**	**15.5**	**15.9**	**8.4**	**39.9**	**48.1**	**26.4**	**21.8**	**28.8**	**40.8**	**24.5**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-99) (Washington, DC, April 1983 - December 1998).

continually rising prices. In fact, oil prices declined over each of the next 4 years. Similarly, the year with the highest average absolute percent error was 1998, followed by 1995 and 1986, with very high percentage errors in the earliest *AEO*s only partially offset by smaller errors in the more recent forecasts. In nominal terms, the first forecast for 1995, from *AEO83*, was nearly \$75 per barrel, compared with the actual 1995 price of \$17.14 per barrel. The sharp drop in the actual 1998 price, to \$12.10 per barrel, resulted from a combination of weak demand from the Asian economies and an oversupply of crude oil exacerbated by the success of Iraq coming on line with more than 1 million barrels of oil production per day.

For many of the variables examined in this paper, the highest average errors are seen for the year 1995. As mentioned before, the 1995 projections include those made furthest in the past—up to 12 years earlier. In addition, projections for 1991 through 1994 are not available from the earliest publications, so that 1995 appears to be more of an outlier.

Table 13. World Oil Prices: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1998

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	Average Absolute Error
(Nominal Dollars per Barrel)															
AEO82	28.49	32.47	37.38	41.90	45.66	49.02									20.23
AEO83	28.44	28.18	30.67	36.07	41.41	46.93					74.25				22.18
AEO84	28.92	28.67	29.56	31.76	34.27	37.00					56.65				16.60
AEO85	27.00	25.70	24.38	25.26	28.60	32.23	34.75	36.99	37.95	40.22	41.14				14.09
AEO86		14.57	15.89	17.28	18.91	20.72	22.20	24.74	28.25	32.08	35.49	38.41	41.03	42.92	10.43
AEO87			18.11	17.41	19.01	20.06	20.97	21.54	23.17	25.76	28.98				4.47
AEO89				14.70	15.00	16.31	17.52	18.47	20.38	23.07	25.72	28.61	31.50	34.06	6.67
AEO90					17.70	17.53					24.45				3.97
AEO91						22.00	24.95	25.64	26.31	26.95	27.56	28.08	28.62	29.16	8.95
AEO92							19.13	20.19	20.72	22.23	23.89	25.50	27.30	28.92	6.37
AEO93								18.90	20.09	20.96	21.99	22.85	23.74	24.69	4.99
AEO94									17.12	17.27	18.26	19.34	20.40	21.50	2.74
AEO95										15.26	17.19	18.04	18.98	19.79	2.21
AEO96											17.24	17.69	18.44	19.30	2.58
AEO97												19.88	19.25	19.11	2.83
AEO98													18.51	18.53	3.23
AEO99														18.19	6.09
Actual Value	**26.99**	**14.00**	**18.13**	**14.56**	**18.08**	**21.76**	**18.70**	**18.20**	**16.14**	**15.51**	**17.14**	**20.64**	**18.53**	**12.10**	
Average Absolute Error	**1.22**	**11.92**	**8.62**	**11.78**	**10.36**	**10.09**	**4.95**	**5.58**	**8.11**	**9.41**	**14.61**	**5.32**	**6.27**	**13.01**	**9.23**
(Percent Error)															
AEO82	5.5	131.9	106.2	187.7	152.5	125.3									118.2
AEO83	5.4	101.3	69.2	147.7	129.1	115.7					333.2				128.8
AEO84	7.2	104.8	63.1	118.2	89.6	70.0					230.5				97.6
AEO85	0.0	83.6	34.5	73.5	58.2	48.1	85.8	103.2	135.1	159.3	140.0				83.8
AEO86		4.1	-12.4	18.7	4.6	-4.8	18.7	35.9	75.0	106.8	107.1	86.1	121.4	254.7	65.4
AEO87			-0.1	19.6	5.1	-7.8	12.1	18.4	43.6	66.1	69.1				26.9
AEO89				1.0	-17.0	-25.1	-6.3	1.5	26.3	48.7	50.1	38.6	70.0	181.5	42.4
AEO90					-2.1	-19.4					42.6				21.4
AEO91						1.1	33.4	40.9	63.0	73.8	60.8	36.0	54.4	141.0	56.1
AEO92							2.3	10.9	28.4	43.3	39.4	23.6	47.3	139.0	41.8
AEO93								3.8	24.5	35.1	28.3	10.7	28.1	104.1	33.5
AEO94									6.1	11.3	6.6	-6.3	10.1	77.7	19.7
AEO95										-1.6	0.3	-12.6	2.4	63.5	16.1
AEO96											0.6	-14.3	-0.5	59.5	18.7
AEO97												-3.7	3.9	57.9	21.8
AEO98													-0.1	53.2	26.6
AEO99														50.4	50.4
Average Absolute Percent Error	**4.5**	**85.1**	**47.6**	**80.9**	**57.3**	**46.4**	**26.5**	**30.7**	**50.2**	**60.7**	**85.3**	**25.8**	**33.8**	**107.5**	**56.7**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-99) (Washington, DC, April 1983 - December 1998).

Although the forecasts of world oil prices appearing in the earlier *AEO*s were almost uniformly too high, from *AEO86* on there were several instances of forecasts that were too low. These included the 1987 and 1990 forecasts appearing in *AEO86* and *AEO87*, the forecasts for 1989 through 1991 appearing in the *Annual Energy Outlook 1989* (*AEO89*)[36] and *AEO90*, and the most recent forecasts for 1996. Clearly, following the oil price collapse of 1986, EIA's forecasts were significantly reduced; as a consequence, the projections for 1990 tended to be too low, in part because of the rise in oil prices beginning in August 1990 associated with Iraq's invasion of Kuwait. Even with the lower price forecasts, 1995 had high percentage errors until *AEO94*, as most *AEO*s continued to show rising prices in response to perceived rising world oil demand.

The early *AEO* projections were strongly influenced by the notion that OPEC would continue to hold a large measure of power in world oil markets. Conventional wisdom in the early projections assumed that OPEC would be able to curtail production sufficiently to hold

[36]Energy Information Administration, *Annual Energy Outlook 1989*, DOE/EIA-0383(89) (Washington, DC, January 1989).

prices up, and that the cartel's members would continue their cooperation throughout the forecast horizon. Even as it became clear that OPEC's cohesiveness was not permanent, EIA continued to assume that oil prices would rise with increasing demand, although at a much slower rate of growth than in the 1970s. Increasing investment in areas outside OPEC and technological advances in oil exploration and production have contributed to the growth in oil reserves and production capacity of non-OPEC producers. These trends, combined with competition from natural gas and energy conservation, have kept prices lower than expected in the earlier forecasts.

Natural Gas Prices

Natural gas prices at the wellhead have had the highest average absolute percentage forecast errors in the *AEO*s, with an overall average error of 70.2 percent (Table 14). Occasionally, near-term gas prices have been underestimated, but most of the projections were overestimates. Similar to the forecasts for world oil prices, those for natural gas prices were highest in the earlier *AEO*s, when

Table 14. Natural Gas Wellhead Prices: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1998

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	Average Absolute Error
(Nominal Dollars per Thousand Cubic Feet)															
AEO82	4.15	5.10	6.02	6.55	6.83	7.11									4.09
AEO83	2.87	2.98	3.25	3.60	4.10	4.64					9.31				2.57
AEO84	2.76	2.82	3.07	3.39	3.81	4.34					7.15				2.08
AEO85	2.60	2.59	2.61	2.62	2.84	3.20	3.62	4.07	4.51	5.00	5.53				1.74
AEO86		1.73	1.96	2.29	2.55	2.82	3.14	3.64	4.12	4.66	5.24	5.81	6.36	6.82	2.12
AEO87			1.83	1.96	2.12	2.30	2.49	2.70	2.98	3.29	3.69				0.86
AEO89				1.62	1.71	1.90	2.10	2.49	2.86	3.18	3.49	4.10	4.35	4.65	1.11
AEO90					1.78	1.89					2.70				0.47
AEO91						1.77	1.91	2.12	2.29	2.38	2.43	2.48	2.56	2.65	0.40
AEO92							1.69	1.86	2.04	2.14	2.32	2.43	2.61	2.80	0.33
AEO93								1.85	1.92	2.06	2.25	2.35	2.47	2.63	0.31
AEO94									1.99	2.13	2.27	2.40	2.56	2.65	0.37
AEO95										1.90	1.99	1.93	2.03	2.09	0.23
AEO96											1.64	1.74	1.85	1.95	0.25
AEO97												2.02	1.81	1.86	0.26
AEO98													2.29	2.16	0.12
AEO99														2.12	0.16
Actual Value	**2.51**	**1.94**	**1.67**	**1.69**	**1.69**	**1.71**	**1.64**	**1.74**	**2.04**	**1.85**	**1.55**	**2.17**	**2.32**	**1.96**	
Average Absolute Error	**0.58**	**1.19**	**1.45**	**1.48**	**1.53**	**1.62**	**0.85**	**0.93**	**0.84**	**1.12**	**2.30**	**0.82**	**0.83**	**1.00**	**1.24**
(Percent Error)															
AEO82	65.2	163.1	260.4	287.8	304.0	315.8									232.7
AEO83	14.5	53.5	94.7	113.3	142.5	171.1					500.6				155.7
AEO84	9.9	45.6	83.6	100.7	125.2	153.9					361.4				125.7
AEO85	3.6	33.5	56.1	55.3	67.9	87.1	121.0	133.8	121.3	170.3	256.5				100.6
AEO86		-10.8	17.2	35.3	50.8	65.0	91.4	108.9	102.2	151.6	238.2	168.0	173.9	247.7	112.4
AEO87			9.6	15.9	25.2	34.4	52.1	54.9	45.9	77.7	137.9				50.4
AEO89				-4.1	1.1	11.3	28.2	42.8	40.1	72.1	125.5	88.7	87.7	137.3	58.1
AEO90					5.3	10.5					74.0				29.9
AEO91						3.5	16.6	21.6	12.2	28.7	57.1	14.3	10.5	35.3	22.2
AEO92							3.3	6.8	-0.1	15.9	49.7	12.1	12.5	42.6	17.9
AEO93								6.3	-5.9	11.5	45.4	8.4	6.3	34.3	16.9
AEO94									-2.4	15.3	46.3	10.5	10.2	35.2	20.0
AEO95										2.4	28.4	-11.0	-12.3	6.6	12.1
AEO96											5.6	-19.8	-20.4	-0.3	11.5
AEO97												-7.1	-22.1	-5.2	11.5
AEO98													-1.2	10.4	5.8
AEO99														8.3	8.3
Average Absolute Percent Error	**23.3**	**61.3**	**86.9**	**87.5**	**90.2**	**94.7**	**52.1**	**53.6**	**41.3**	**60.6**	**148.2**	**37.8**	**35.7**	**51.2**	**70.2**

AEO = *Annual Energy Outlook.*

Note: *AEO82* projections given in Btu were converted to trillion cubic feet using a conversion factor of 1.03.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-99) (Washington, DC, April 1983 - December 1998).

the projections for all prices were influenced by the assumption that market forces would tend to increase demand for, and therefore prices of, natural gas and coal in response to higher world oil prices.

The year 1995 had the highest average absolute percent error; with the exception of *AEO96*, which was essentially estimating the recent historical year for 1995, the smallest error for 1995 was 28.4 percent in *AEO95*. The 1995 wellhead price was significantly lower than the price in other recent years, primarily because 1995 had the second mildest winter in the United States in the past 20 years. The large error reflects the forecast assumptions of average weather. The year with the lowest average absolute percent error was 1985, with an average absolute error for four *AEO*s of 23.3 percent, even including the 65.2-percent error in the *AEO82* projection for 1985. Despite the large errors, the forecasts in each subsequent *AEO* have tended to show considerable improvement, as the downward trend in gas prices has been better captured from one *AEO* to another.

Nevertheless, each *AEO* has tended to predict rising natural gas prices over time, either because of the assumption in the earlier *AEO*s that long-term, high-priced contracts would continue or because technological improvement was not expected to offset depletion effects in the more recent forecasts. In summary, three factors have had significant impacts on the projections:

- In the earlier *AEO*s, it was assumed that natural gas contracts whose provisions were governed by the Natural Gas Policy Act of 1978 would not be abrogated and that the prices that prevailed under those contracts would essentially set the market price over time. In fact, when oil prices fell in 1986, many of those contracts were abrogated, and the price of natural gas fell, although not as much as the price of oil. In addition, before *AEO90*, technology was assumed to remain at existing levels. Since then, assumptions about oil and gas technological improvements have been progressively implemented and improved in the supply module.

- Estimates of the technically recoverable resource have increased over time, while exploration and production costs per unit of output have generally declined. Correspondingly, the resource base assumed in the oil and gas supply model has increased and estimated per unit costs have generally declined over the years. In addition, more recent *AEO*s have allowed for increases in the economically recoverable resource base or in the finding rates for oil and gas due to technology improvements. The impact on costs due to technological improvements has been captured in more recent versions of the model as well.

- Consistent with the assumption of existing regulations, the earlier *AEO*s did not assume that there would be additional competition in the transmission and distribution sectors of the market; however, from 1985 on, FERC moved to open access to the interstate pipeline transmission system, generally lowering end-use prices and stimulating additional price competition at the wellhead as well.

Thus, although the forecasts have generally improved with additional information, their accuracy has been impacted by the changing competitive structure of the industry and underestimates of technological advances by oil and gas producers.

It is worth noting that much of the observed variation in natural gas price in more recent years can be attributed to transitory effects (e.g., weather and storage levels) that are not predictable in the long term and are more likely to affect prices in an increasingly competitive market environment. This effect has added to the complexity of forecasting natural gas prices over the longer term and, in part, explains why actual prices will vary from price forecasts based on assumptions of average conditions.

Coal Prices to Electric Utilities

Although they are better than those for oil and gas prices, the *AEO* forecasts of coal prices to electric utilities still show an average absolute percent error of 35.9 percent over the period studied (Table 15). All forecasts were overstated. The forecasts for 1995 had the highest average absolute percent error of 57.3 percent. There was, however, significant improvement in the 1995 forecast over time, with the error improving from 137.7 percent in *AEO83* to 10.5 percent in *AEO95* (excluding *AEO96*, which provided an estimate for the historical year 1995 based on partial year data). Across forecast years, the further out the forecast, the higher the error, with the lowest average absolute percent error shown for the year 1985 at 13.3 percent.

The early *AEO*s—*AEO82* through *AEO86*—tended to have the highest average absolute percent errors, exacerbated by their forecasts for 1995. There was steady improvement in the *AEO*s through *AEO90*, which had an average absolute percent error of 16.8. After *AEO90*, overestimates for 1995 through 1998 adversely affected the overall average errors for a number of the subsequent *AEO*s.

The major factors in the high forecasts of coal prices were assumptions about depletion effects, productivity improvements, capacity utilization, transportation, and the impacts of CAAA90. Depletion was assumed to overcome productivity improvements in the long run;

Table 15. Coal Prices to Electric Utilities: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1998

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	Average Absolute Error
							(Nominal Dollars per Million Btu)								
AEO82	1.95	2.02	2.10	2.20	2.32	2.48									0.66
AEO83	1.95	2.02	2.10	2.19	2.31	2.43					3.13				0.82
AEO84	1.89	1.96	2.04	2.13	2.25	2.37					2.90				0.73
AEO85	1.68	1.75	1.82	1.89	1.98	2.09	2.18	2.27	2.36	2.43	2.51				0.63
AEO86		1.61	1.68	1.75	1.84	1.94	2.04	2.13	2.23	2.33	2.43	2.50	2.56	2.62	0.73
AEO87			1.52	1.56	1.66	1.76	1.85	1.94	2.04	2.12	2.21				0.43
AEO89				1.50	1.52	1.67	1.75	1.81	1.88	1.95	2.01	2.06	2.13	2.16	0.48
AEO90					1.46	1.53					1.91				0.22
AEO91						1.51	1.59	1.67	1.76	1.85	1.91	1.97	2.03	2.07	0.46
AEO92							1.55	1.62	1.67	1.75	1.83	1.91	1.93	1.99	0.44
AEO93								2.00	1.53	1.59	1.67	1.71	1.78	1.81	0.40
AEO94									1.51	1.56	1.64	1.72	1.76	1.77	0.35
AEO95										1.42	1.46	1.47	1.52	1.54	0.18
AEO96											1.35	1.34	1.36	1.36	0.07
AEO97												1.35	1.37	1.37	0.09
AEO98													1.27	1.27	0.01
AEO99														1.31	0.05
Actual Value	**1.65**	**1.58**	**1.51**	**1.47**	**1.45**	**1.46**	**1.45**	**1.41**	**1.39**	**1.36**	**1.32**	**1.29**	**1.27**	**1.26**	
Average Absolute Error	**0.22**	**0.29**	**0.37**	**0.42**	**0.47**	**0.52**	**0.38**	**0.51**	**0.48**	**0.53**	**0.76**	**0.49**	**0.50**	**0.49**	**0.49**
							(Percent Error)								
AEO82	18.1	28.2	39.3	50.0	59.7	70.1									44.2
AEO83	18.4	27.8	39.6	49.4	59.1	66.6					137.7				57.0
AEO84	14.7	24.4	35.2	45.5	54.9	62.2					120.3				51.0
AEO85	1.9	10.7	21.0	28.8	36.5	43.1	51.0	60.8	69.5	78.4	90.4				44.7
AEO86		2.0	11.6	19.5	26.6	32.8	41.0	51.1	60.3	71.6	84.2	93.8	101.7	107.7	54.1
AEO87			0.9	6.7	14.6	20.4	27.8	37.2	46.6	56.2	67.8				30.9
AEO89				2.3	4.9	14.7	21.1	28.3	35.5	43.6	52.5	59.7	67.4	71.6	36.5
AEO90					0.7	5.1					44.6				16.8
AEO91						3.4	9.9	18.0	27.0	36.2	44.6	52.3	59.6	64.5	35.1
AEO92							7.0	15.0	19.9	28.8	38.6	47.8	52.1	57.8	33.4
AEO93								41.8	10.0	16.7	26.6	32.6	40.0	43.5	30.2
AEO94									8.5	14.4	24.8	33.3	38.8	40.6	26.7
AEO95										4.7	10.5	14.2	19.9	22.1	14.3
AEO96											2.4	4.2	7.0	8.2	5.5
AEO97												5.0	7.9	9.1	7.3
AEO98													0.3	0.6	0.4
AEO99														4.3	4.3
Average Absolute Percent Error	**13.3**	**18.6**	**24.6**	**28.9**	**32.1**	**35.4**	**26.3**	**36.0**	**34.6**	**39.0**	**57.3**	**38.1**	**39.5**	**39.1**	**35.9**

AEO = Annual Energy Outlook.
Btu = British thermal unit.
Sources: **Actual Values:** Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(99/05) (Washington, DC, May 1999). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-99) (Washington, DC, April 1983 - December 1998).

however, the onset of such new technology as longwall mines and the growth of surface mining in the West have led to continuing productivity improvements. Similarly, with high world oil price forecasts, the impacts of excess capacity and competition among existing mines were not seen to be as important as they in fact became. In addition, high world oil prices were assumed to affect both the production process and the costs of transportation. In fact, the collapse of oil prices in 1986 reduced the impact on both, and the increasing competitiveness of rail transportation has held transportation costs below expectations. Finally, it was assumed that higher prices would follow the enactment of CAAA90 as the demand for low-sulfur coal increased. Price increases did not materialize, however, as productivity increases and transportation cost reductions made increased production from western mines possible at lower-than-anticipated prices. In addition, it was assumed that many coal boilers would not be able to burn western coal easily, an assumption that proved erroneous.

Average Electricity Prices

Average electricity prices showed the best forecasting record among the prices examined here, with an average absolute percent error of 11.1 percent (Table 16). As with all the price forecasts, because of the projections made 12 years earlier, the year with the highest average absolute percent error was 1995, which had an average error of 15.4 percent. Except for the two near-term forecasts of 1985 for *AEO82* and 1989 for *AEO90*, price forecasts have been higher than actual. By publication, *AEO83* had the highest average absolute error of 18.1 percent and the *Annual Energy Outlook 1998* (*AEO98*)[37] the lowest at 0.2 percent. Recent *AEO*s, from the *Annual Energy Outlook 1992* (*AEO92*)[38] on, have had average absolute percent errors of 10.2 percent or less.

The primary reason for high price forecasts was the impact of fuel costs and capital costs on expected prices. Fuel costs were consistently overestimated for oil,

Table 16. Average Electricity Prices: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1998

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	Average Absolute Error
(Nominal Cents per Kilowatthour)															
AEO82	6.13	6.49	6.88	7.18	7.50	7.87									0.65
AEO83	6.72	6.98	7.26	7.54	7.80	8.09					9.59				1.20
AEO84	6.63	6.88	7.14	7.38	7.59	7.84					8.84				0.96
AEO85	6.62	6.89	7.18	7.40	7.60	7.79	7.95	8.07	8.14	8.23	8.32				1.03
AEO86		6.67	6.89	7.05	7.20	7.38	7.50	7.46	7.47	7.64	7.85	8.06	8.26	8.39	0.82
AEO87			6.63	6.69	6.96	7.17	7.40	7.54	7.67	7.84	8.02				0.65
AEO89				6.50	6.78	7.13	7.39	7.54	7.62	7.78	7.93	8.07	8.26	8.41	0.83
AEO90					6.49	6.73					7.73				0.32
AEO91						6.94	7.36	7.61	7.78	8.06	8.14	8.14	8.18	8.18	1.00
AEO92							7.01	7.20	7.34	7.55	7.68	7.79	7.89	7.95	0.70
AEO93								7.19	7.30	7.44	7.61	7.71	7.85	7.89	0.70
AEO94									6.98	7.15	7.42	7.56	7.70	7.78	0.55
AEO95										6.97	7.12	7.15	7.29	7.37	0.30
AEO96											7.26	7.29	7.33	7.41	0.45
AEO97												7.03	7.16	7.24	0.28
AEO98													6.93	6.80	0.02
AEO99														6.97	0.17
Actual Value	**6.40**	**6.40**	**6.40**	**6.40**	**6.50**	**6.60**	**6.70**	**6.80**	**6.90**	**6.90**	**6.90**	**6.90**	**6.90**	**6.80**	
Average Absolute Error	**0.26**	**0.38**	**0.60**	**0.70**	**0.74**	**0.84**	**0.73**	**0.72**	**0.64**	**0.73**	**1.06**	**0.74**	**0.78**	**0.87**	**0.75**
(Percent Error)															
AEO82	-4.3	1.4	7.5	12.2	15.4	19.3									10.0
AEO83	5.1	9.1	13.5	17.8	20.1	22.6					39.0				18.1
AEO84	3.6	7.5	11.6	15.3	16.8	18.7					28.2				14.5
AEO85	3.4	7.7	12.2	15.6	16.9	18.0	18.7	18.7	18.0	19.3	20.6				15.4
AEO86		4.2	7.6	10.1	10.7	11.9	11.9	9.7	8.3	10.8	13.8	16.8	19.8	23.4	12.2
AEO87			3.6	4.6	7.0	8.6	10.5	10.8	11.1	13.6	16.2				9.6
AEO89				1.5	4.3	8.0	10.2	11.0	10.4	12.8	14.9	17.0	19.6	23.7	12.1
AEO90					-0.2	2.0					12.0				4.7
AEO91						5.2	9.8	11.9	12.8	16.8	18.0	18.0	18.5	20.3	14.6
AEO92							4.6	5.9	6.4	9.4	11.4	12.9	14.4	17.0	10.2
AEO93								5.8	5.8	7.9	10.3	11.7	13.7	16.1	10.2
AEO94									1.1	3.6	7.5	9.5	11.6	14.5	8.0
AEO95										1.0	3.3	3.6	5.6	8.3	4.4
AEO96											5.2	5.7	6.2	8.9	6.5
AEO97												1.9	3.8	6.5	4.0
AEO98													0.4	0.0	0.2
AEO99														2.6	2.6
Average Absolute Percent Error	**4.1**	**6.0**	**9.3**	**11.0**	**11.4**	**12.7**	**11.0**	**10.5**	**9.2**	**10.6**	**15.4**	**10.8**	**11.4**	**12.8**	**11.1**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-99) (Washington, DC, April 1983 - December 1998).

[37]Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997).
[38]Energy Information Administration, *Annual Energy Outlook 1992*, DOE/EIA-0383(92) (Washington, DC, January 1992).

natural gas, and coal, with a strong effect on the estimates of electricity prices, especially for *AEO82* through *AEO84*. In addition, the costs of new capacity were assumed to be higher in earlier projections than they actually turned out to be, and this assumption also helped to raise the forecasts. Finally, a 1992 study[39] on the accuracy of *AEO* electricity forecasts for 1985 and 1990 indicated that part of the explanation for high price estimates was public utility commission disallowances and phase-ins of costs of some capital-intensive generating capacity that were not incorporated in the projections because actual regulatory practices varied from those assumed in the projections. For example, some nuclear units had significant shares of their costs disallowed, and the remaining costs were phased in on a longer time schedule than the utilities had requested, contributing to lower-than-expected prices in some years.

Gross Domestic Product

The economic forecasts in the *AEO*s are based on projections from DRI / McGraw-Hill, adjusted for EIA's world oil price projections. The forecasts for gross domestic product (GDP) show an average absolute percent error of 5.0 percent (Table 17). Most of the projections have been less than 10 percent from actual, with the exception of some of the forecasts in *AEO83*, *AEO84*, *AEO85*, *AEO86*, and *AEO89* for the mid-1990s, which ranged up to 28.8 percent above the actual GDP. In general, from *AEO82* through *AEO90*, the GDP forecasts tended to be underestimated for the earlier years and overestimated for the later years. In subsequent reports, GDP has been consistently underestimated.

The major reason for the pattern of overestimates in the longer term forecasts in the early *AEO*s is the recession that began in the latter part of 1990 and continued into 1991. The economic forecasts produced for the *AEO* are trend forecasts, which do not attempt to foresee the timing or magnitude of business cycles. The economic cycle in 1990-91 created a breakpoint in the series being used for evaluating forecast errors. Therefore, early *AEO*s did not forecast the recession and, consequently, overestimated long-term growth beyond 1991. Conversely, the underestimates in later *AEO*s resulted in part from overestimates of world oil prices, which tend to dampen economic growth, plus several other factors such as actual utility bond rates being lower than expected.

Moving Average Analysis of Forecasts

Methodology

All the preceding analyses have focused on comparing the projections from previous *AEO*s with actual historical values. This section describes a simple moving average analysis of forecast data from the six consumption tables, the four price tables, and the economic growth table above. For each of the tables under consideration, the absolute value of the difference between the projected and actual values was calculated for each *AEO* and each year. Then, a 5-year moving average was calculated for each *AEO*, starting with the most recent forecast year. (The Appendix to this paper provides an example of the moving average analysis performed for the total energy consumption table.) Table 18 contains the result of the analysis for the 11 tables under consideration for the *AEO*s from *AEO85* to *AEO95*. No results are given for *AEO90*, because there are not enough values in the intervening years to compute a 5-year moving average.

Results

In general, for the more recent *AEO*s, the errors in the coal consumption and electricity sales tables increased but those in the total petroleum and natural gas consumption tables did not. The errors in the price tables decreased from *AEO85* through *AEO89*, rose sharply in *AEO91*, especially for oil prices and electricity prices, then declined again through *AEO95*.

Total petroleum consumption errors declined in more recent *AEO*s as forecasts of petroleum consumption improved after *AEO90*. In contrast, coal consumption errors increased substantially over time, with the worst errors occurring from *AEO92* to *AEO95*. The largest errors were in the forecasts for 1996, 1997, and 1998—years in which there was a surge in coal consumption for electricity generation that had not been captured in *AEO92* to *AEO95*. Electricity sales forecasts improved through *AEO91* but got progressively worse from *AEO92* to *AEO95*, which severely underestimated sales for the years 1996 through 1998 (Table 6).

[39]"Forecasting Accuracy of the Electricity Market Model," prepared by the Nuclear and Electricity Analysis Branch, Energy Information Administration (unpublished manuscript, July 30, 1992).

Table 17. Gross Domestic Product: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1998

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	Average Absolute Error
							(Billion Nominal Dollars)								
AEO82	3,939	4,306	4,733	5,201	5,712	6,288									225
AEO83	3,919	4,264	4,650	5,086	5,549	6,053					9,362				430
AEO84	3,910	4,191	4,589	5,031	5,490	5,979					9,098				391
AEO85	3,882	4,103	4,436	4,793	5,207	5,658	6,158	6,702	7,252	7,836	8,486				450
AEO86		4,203	4,434	4,741	5,015	5,371	5,795	6,244	6,726	7,270	7,875	8,524	9,226	9,973	480
AEO87			4,483	4,701	5,035	5,389	5,773	6,190	6,666	7,175	7,716				255
AEO89				4,857	5,182	5,575	6,013	6,483	6,987	7,525	8,106	8,756	9,400	10,103	615
AEO90					5,236	5,550					7,882				336
AEO91						5,457	5,695	6,078	6,399	6,738	7,145	7,607	8,099	8,629	150
AEO92							5,648	5,992	6,346	6,710	7,115	7,530	7,968	8,456	182
AEO93								5,941	6,339	6,714	7,117	7,542	7,995	8,509	164
AEO94									6,264	6,622	6,944	7,298	7,679	8,070	364
AEO95										6,761	7,090	7,418	7,837	8,244	230
AEO96											7,057	7,356	7,754	8,151	309
AEO97												7,585	7,881	8,265	184
AEO98													8,060	8,439	62
AEO99														8,478	33
Actual Value	**4,181**	**4,422**	**4,692**	**5,050**	**5,439**	**5,744**	**5,917**	**6,244**	**6,558**	**6,947**	**7,270**	**7,662**	**8,111**	**8,511**	
Average Absolute Error	**277**	**209**	**152**	**187**	**244**	**284**	**182**	**210**	**285**	**356**	**676**	**362**	**402**	**423**	**337**
							(Percent Error)								
AEO82	-5.8	-2.6	0.9	3.0	5.0	9.5									4.5
AEO83	-6.2	-3.6	-0.9	0.7	2.0	5.4					28.8				6.8
AEO84	-6.5	-5.2	-2.2	-0.4	0.9	4.1					25.1				6.3
AEO85	-7.1	-7.2	-5.5	-5.1	-4.3	-1.5	4.1	7.3	10.6	12.8	16.7				7.5
AEO86		-5.0	-5.5	-6.1	-7.8	-6.5	-2.1	0.0	2.6	4.6	8.3	11.2	13.7	17.2	7.0
AEO87			-4.5	-6.9	-7.4	-6.2	-2.4	-0.9	1.6	3.3	6.1				4.4
AEO89				-3.8	-4.7	-2.9	1.6	3.8	6.5	8.3	11.5	14.3	15.9	18.7	8.4
AEO90					-3.7	-3.4					8.4				5.2
AEO91						-5.0	-3.7	-2.7	-2.4	-3.0	-1.7	-0.7	-0.1	1.4	2.3
AEO92							-4.5	-4.0	-3.2	-3.4	-2.1	-1.7	-1.8	-0.6	2.7
AEO93								-4.9	-3.3	-3.4	-2.1	-1.6	-1.4	0.0	2.4
AEO94									-4.5	-4.7	-4.5	-4.8	-5.3	-5.2	4.8
AEO95										-2.7	-2.5	-3.2	-3.4	-3.1	3.0
AEO96											-2.9	-4.0	-4.4	-4.2	3.9
AEO97												-1.0	-2.8	-2.9	2.2
AEO98													-0.6	-0.8	0.7
AEO99														-0.4	0.4
Average Absolute Percent Error	**6.4**	**4.7**	**3.2**	**3.7**	**4.5**	**4.9**	**3.1**	**3.4**	**4.4**	**5.1**	**9.3**	**4.7**	**5.0**	**5.0**	**5.0**

AEO = *Annual Energy Outlook*.

Sources: **Actual Values:** 1985-1997—Council of Economic Advisors, *Economic Report of the President* (Washington, DC, February 1999). 1998—U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, April 1999). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-99) (Washington, DC, April 1983 - December 1998).

Natural gas consumption errors were very high prior to *AEO90* and improved in more recent *AEO*s. As discussed above, in the 1980s there were significant changes in the natural gas industry, with very large price forecasts causing a significant underestimation of consumption (Table 4), especially for the years 1995 to 1998. Also, FUA legislation exacerbated the error by attempting to restrict gas use. Forecasts improved considerably after *AEO90*.

Oil price forecasts in *AEO91* had a much higher error than subsequent *AEO*s, attributable to the Iraqi invasion of Kuwait. In view of the short-term escalation in oil prices *AEO91* projected continually rising prices. In actuality, oil prices declined over each of the next 4 years, 1990 to 1994, which were the years included in the 5-year moving average. Subsequent *AEO*s were better at predicting oil prices.

Table 18. Results of 5-Year Moving Average Analysis of Errors for Selected *AEO* Forecasts

Table in This Article	*AEO85*	*AEO86*	*AEO87*	*AEO89*	*AEO90*	*AEO91*	*AEO92*	*AEO93*	*AEO94*	*AEO95*
Table 2 Total Energy Consumption (Quadrillion Btu)	1.2	2.1	1.5	0.9	—	0.7	0.7	0.9	1.0	1.7
Table 3 Total Petroleum Consumption (Million Barrels per Day)	0.76	0.78	0.36	0.48	—	0.22	0.08	0.16	0.27	0.26
Table 4 Total Natural Gas Consumption (Trillion Cubic Feet)	0.65	0.82	1.23	0.86	—	0.45	0.51	0.41	0.72	0.65
Table 5 Total Coal Consumption (Million Short Tons)	18	13	22	11	—	10	25	22	46	55
Table 6 Total Electricity Sales (Billion Kilowatthours)	42	73	70	30	—	19	32	54	84	91
Table 13 World Oil Prices (Dollars per Barrel)	7.84	1.48	1.55	2.02	—	7.11	4.09	3.43	1.41	2.21
Table 14 Natural Gas Wellhead Prices (Dollars per Thousand Cubic Feet)	0.75	0.61	0.46	0.30	—	0.30	0.25	0.27	0.30	0.23
Table 15 Coal Prices to Electric Utilities (Dollars per Million Btu)	0.29	0.27	0.20	0.20	—	0.26	0.30	0.35	0.31	0.18
Table 16 Average Electricity Prices (Cents per Kilowatthour)	0.72	0.58	0.45	0.47	—	0.77	0.52	0.57	0.46	0.30
Table 17 Gross Domestic Product (Billion Dollars)	273	317	292	191	—	209	225	206	348	230

Note: No results are shown for *AEO90* because there are not enough values in the intervening years to compute a 5-year moving average.

Source: Tables 2, 3, 4, 5, 6, 13, 14, 15, 16, and 17.

Although the downward trend in natural gas prices was better captured from one *AEO* to another, the coal price forecasts had a mixed record. After *AEO91* rising coal prices were predicted, whereas the actual trend was downward. The error was particularly large for 1995 and 1996, which are not included in the 5-year moving average until *AEO92*.

The sharply higher error for electricity price in *AEO91* was due in part to the recession in the latter part of 1990 and early 1991, and to the overestimation of world oil prices, which caused the severe overestimation of electricity prices in *AEO91*. Subsequent *AEO*s were better at predicting electricity prices.

In summary, the moving average analysis gave mixed results. The errors calculated for the consumption tables, except for petroleum and natural gas, increased with more recent *AEO*s, while the errors for the price tables decreased over time. Also, a 5-year moving average accentuates the error occurring during the 5 years included in the calculation but misses any impact after that.

Conclusion

Although a primary function of the models used by EIA to produce its *AEO* projections has been and remains the analysis of alternative policies, many readers of the *AEO* use the projected numbers as forecasts for their own purposes. Thus, it is useful for EIA analysts and users of the *AEO* to know the size of and reasons for the differences between the projections and actual values.

Throughout the *AEO*s, the variables with the highest errors, expressed as average absolute percent errors, have been prices and net imports of natural gas and coal. Natural gas, in general, has been the fuel with the most inaccurate forecasts, showing the highest average error of all the fuels for consumption, production, and prices. Natural gas was the last fossil fuel to be deregulated following the heavy regulation of energy markets in the 1970s and early 1980s, and the early *AEO*s assumed that natural gas would continue to be regulated until new rules were actually promulgated. Even after deregulation, the behavior of natural gas in competitive markets was difficult to predict.

The overestimation of prices is the most striking feature of this evaluation. In general, more rapid technological improvements, the erosion of OPEC's market power, excess productive capacity, and market competitiveness were the factors that the *AEO* forecasts failed to anticipate. While the errors for prices were large, they appeared to have a relatively minor impact on the overall projections of demand and production, although some forecasts were clearly affected, possibly confirming the relatively low price elasticities of supply and demand embedded in the models. For the period covered by this study, productivity and technology improvements and the effects of gradual deregulation and changes in industry structure, such as the treatment of contracts, have more than offset the factors that have tended to raise fossil fuel prices. In addition, energy markets have evolved differently than projected as a result of changes in the regulatory environment and the enactment of changes in legislation, regulations, and standards.

In conclusion, there are several major reasons why forecasts might deviate from their long-term trends. First are laws and regulatory changes over which there is no control, some of which have been discussed in this paper. Second are external factors that cannot be predicted, including such cyclical events as weather and economic downturns, which led to the drop in oil prices in 1991. The final major reason is technological development. Over the years we have addressed this issue.

The NEMS model was introduced in *AEO94*, and we have included in the design a structure that looks at technology in a more detailed fashion. There has been an improvement in the capability to represent technological innovation. Examples of this are electricity generation and technological improvement in oil and gas supply. While the oil and gas model reflects the assumption that increases in cumulative drilling lower the finding rates for oil and gas, recent changes to the methodology allow the flexibility for this decline to be either partially, fully, or more than fully offset by improvements in technology—depending on the fuel, region, and year—based on historical patterns and on assumed future rates of technology improvement. The advantage of this approach is that it is capable of representing finding rates that rise, remain constant, or decline over time, depending on the values of the technology and resource depletion parameters.

In the end-use models there is an emphasis on specific technologies and their characteristics, technology and fuel choice, and stock turnover rates, which is in contrast to the earlier models. As a specific component for new generating technologies, there is learning-by-doing—that is, as experience is gained with new technologies the cost starts dropping. These improvements to NEMS have allowed the execution of a number of technology cases in *AEO99* to examine their impacts. Other technology cases have been produced in *AEO*s since *AEO94*.

The most striking result of the moving average analysis described here is that the price predictions and the petroleum and natural gas consumption predictions became more accurate with more recent *AEO*s, while the coal consumption and electricity sales errors increased with more recent *AEO*s. Also, a 5-year moving average accentuates the error occurring during the 5 years and misses any impact outside the 5-year range.

Appendix
Example of 5-Year Moving Average Analysis

Table A1. Total Energy Consumption: *AEO* Forecasts, Actual Values, Absolute Errors, and 5-Year Moving Average of Absolute Errors, 1985-1998

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	Average Absolute Error
						(Quadrillion Btu)									
AEO82	79.1	79.6	79.9	80.8	82.0	83.3									1.8
AEO83	78.0	79.5	81.0	82.4	83.8	84.6					89.5				1.2
AEO84	78.5	79.4	81.2	83.1	85.0	86.4					93.5				1.6
AEO85	77.6	78.5	79.8	81.2	82.6	83.3	84.2	85.2	85.9	86.7	87.7				1.3
AEO86		77.0	78.8	79.8	80.6	81.5	82.9	84.0	84.8	85.7	86.5	87.9	88.4	88.8	3.2
AEO87			78.9	80.0	81.9	82.8	83.9	85.3	86.4	87.5	88.4				1.5
AEO89				82.2	83.7	84.5	85.4	86.4	87.3	88.2	89.2	90.8	91.4	91.9	1.4
AEO90					84.2	85.4					91.9				0.8
AEO91						84.4	85.0	86.0	87.0	87.9	89.1	90.4	91.8	93.1	1.4
AEO92							84.7	87.0	88.0	89.2	90.5	91.4	92.4	93.4	1.1
AEO93								87.0	88.3	89.8	91.4	92.7	94.0	95.3	0.9
AEO94									88.0	89.5	90.7	91.7	92.7	93.6	1.0
AEO95										89.2	90.0	90.6	91.9	93.0	1.6
AEO96											90.6	91.3	92.5	93.5	1.4
AEO97												92.6	93.6	95.1	1.0
AEO98													94.7	96.7	1.4
AEO99														94.6	0.4
Actual Value	76.8	77.0	79.6	83.0	84.5	84.1	84.0	85.5	87.3	89.3	91.0	94.0	94.4	94.2	
						(Absolute Error)									**5-Year Moving Average**
AEO85	0.8	1.5	0.2	1.8	1.9	0.8	0.2	0.3							1.2
AEO86		0.0	0.8	3.2	3.9	2.6	1.1	1.5	2.5						2.1
AEO87			0.7	3.0	2.6	1.3	0.1	0.2	0.9	1.8					1.5
AEO89				0.8	0.8	0.4	1.4	0.9	0.0	1.1	1.8				0.9
AEO90															
AEO91						0.3	1.0	0.5	0.3	1.4	2.0	3.6	2.6		0.7
AEO92							0.7	1.5	0.7	0.2	0.5	2.6	2.0	0.8	0.7
AEO93								1.5	1.0	0.5	0.4	1.3	0.4	1.1	0.9
AEO94									0.7	0.2	0.3	2.3	1.7	0.6	1.0
AEO95										0.1	1.0	3.4	2.5	1.2	1.7
AEO96											0.4	2.7	1.9	0.7	
AEO97												1.4	0.8	0.9	
AEO98													0.3	2.5	
AEO99														0.4	

AEO = Annual Energy Outlook.

Btu = British thermal unit.

Note: Includes nonelectric renewables.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-99) (Washington, DC, April 1983 - December 1998).

National Energy Modeling System/ *Annual Energy Outlook* Conference Summary

*This paper presents a summary of the seventh annual National Energy Modeling System/*Annual Energy Outlook *conference held on March 22, 1999. The remarks for each speaker were summarized by the session moderators and are not intended to serve as transcripts of the sessions. The comments and opinions of speakers outside the Energy Information Administration (EIA) are their own and do not necessarily reflect the views of EIA. In some cases, speakers were chosen who have different views from those of EIA in order to have a wider range of opinions in the sessions.*

Introduction

On March 22, 1999, the Office of Integrated Analysis and Forecasting (OIAF), Energy Information Administration (EIA), hosted the seventh annual National Energy Modeling System / *Annual Energy Outlook* Conference. These conferences are open to the general public and attract a wide range of participants from other Federal and State government agencies, trade associations, energy industries, private corporations, consulting firms, and academia.

Earlier National Energy Modeling System / *Annual Energy Outlook* conferences concentrated on the initial development of the National Energy Modeling System (NEMS) and the underlying model methodologies and on the results of the first *Annual Energy Outlook* developed using NEMS. Recent conferences have focused less on specific projections and model developments and more on energy issues, key analytical assumptions, and their potential impacts on energy markets.

Keynote Address
The Joy of Flexibility: U.S. Climate Policy in the Next Decade

Paul R. Portney, President, Resources for the Future, Washington, DC

Flexibility in the design and timing of climate mitigation measures can greatly affect the costs that must be borne. Two types of flexibility have been singled out for most of the attention. The first, "*where* flexibility," concerns the actual location of the greenhouse gas emissions reductions that a country might agree to take. The United States has insisted that any climate agreement give those upon whom falls the initial burden of emissions reductions the option to buy an equivalent reduction someplace else in the world. The creation of a market for emissions reductions—particularly an international market—has the potential to greatly reduce the costs associated with whatever emissions reduction obligations are agreed upon.

The second kind of flexibility, "*when* flexibility," pertains to the schedule according to which emissions are reduced. Any initiative that calls for substantial emissions reductions in a relatively short period of time will be much more expensive than one that proceeds more gradually. This is because the latter approach *will not* necessitate the premature writeoff of capital investments, and *will* allow us to take advantage of the fruits of research and development into less carbon-intensive technologies.

A third kind of flexibility, "*what* flexibility," relates to the greenhouse gases that are covered. However, determining baseline emissions of methane and some of the other greenhouse gases and verifying future emissions reductions will be much more difficult than for carbon dioxide. Another type of flexibility, "*whether* flexibility," examines whether the United States ought to take the Kyoto Protocol very seriously at all. It appears that virtually no one thinks that the Kyoto Protocol has any chance of coming into effect in its current form. One key reason is that the Kyoto Protocol requires no emissions reductions from developing countries, even though the United States insisted going into Kyoto that "meaningful participation" on their part was a *sine qua non* of any agreement. Yet developing countries will not compromise their future growth potential to help solve a problem that was largely the doing of the developed nations. Another problem with the Kyoto Protocol is the nagging concern that it would prove too costly to implement given its current targets and timetables.

According to Portney, it is unlikely that the American public would be willing to accept the kinds of energy price increases that serious analysis suggests might be necessary to meet the goals of the Kyoto Protocol absent international emissions trading. Another concern is that the Kyoto Protocol does nothing to reduce emissions of carbon dioxide before the 2008 through 2012 period.

Four economists at Resources for the Future recently published a proposal designed to effect emissions reductions in the United States beginning in 2002, with the following elements. First, it calls for mandatory emissions reductions in the United States during the period 2002 through 2008, to be brought about through an auctioned permit system. Second, in contrast to the Kyoto Protocol, the proposal is modest. It would cap carbon emissions at 1996 levels, which are about 10 percent greater than 1990 levels and about 10 percent less than carbon emissions are forecast to be in 2002, or 20 percent below forecasted emissions in 2008. Third, in order to guard against the possibility that meeting this goal would prove prohibitively expensive, there is a safety valve built in. Specifically, if the price of a permit should rise above $25 a ton in 2002, the government would offer extra permits—as many as are desired—at that price. This safety valve price would go up 7 percent a year above inflation from 2002 through 2008. Fourth, the proposal is designed to be equitable. Since it will increase household costs of energy and other goods, three-quarters of the revenues raised in the first year would be returned directly to households in the form of a rebate. The remaining 25 percent would be returned to the States, based on the vulnerability of low-income households and industries.

The proposal has several attractive features. First, because it is modest there might even be a chance it could be adopted. Because of the safety valve feature, the marginal program costs are assured, and information can be learned about carbon mitigation costs, for which wildly divergent estimates have been given.

Second, a program such as this would send a measured and gradual message to energy producers and consumers that they will have to pay closer attention to energy conservation opportunities in the future. Third, this program would be a signal to the developing countries that the United States is indeed willing to act first to curb its emissions of greenhouse gases. Fourth, valuable experience into the operation of a greenhouse gas trading system can be gained.

There are limitations to this proposal: it begins to deal unilaterally with what is recognized as an international problem; it requires action where some prefer to see inaction; and it stops far short of where others think the United States needs to go. However, the proposal's authors seem to have it about right.

The full text for this address is posted at the Resources for the Future Weathervane site at www.weathervane.rff.org / refdocs / portney_flex.pdf.

Meeting U.S. Carbon Targets

Moderator: Andy S. Kydes, Energy Information Administration

More than 80 countries have signed the Kyoto Protocol, but none of the Annex I developed countries with specific carbon emissions targets has ratified it through a parliamentary process. Only two countries (with no carbon emissions targets) had ratified the Protocol as of March 1, 1999. As the first speaker noted, ". . . no criteria, guidelines or modalities of operation were agreed to at Kyoto" and "all practical questions remained to be resolved." The meeting of the parties in Buenos Aires provided little progress except to set a schedule for resolving the issues by the sixth Conference of the Parties in 2000. This session outlined the remaining issues of implementing the Kyoto Protocol and provided alternative perspectives on the cost of meeting the goals of the Protocol.

Unresolved Issues and Political Challenges to Implementing the Kyoto Protocol

Irving Mintzer, Global Business Network

After outlining the principles and agreements—trading, inclusion of five additional greenhouse gases, joint implementation, and the Clean Development Mechanism—of the Kyoto Protocol, Dr. Mintzer noted that no criteria, guidelines, or modalities of operation were agreed to at Kyoto and that all practical questions remain to be resolved. Some of the key unresolved issues include: how is a ton defined with respect to global warming, for example, carryovers from previous periods; who can hold or trade tons; when is a ton a ton; is one ton as good as another; what if a party or entity has too many tons and not enough permits; how will baselines be set without requiring a workforce of 1,000 Ph.D.s on each project; is there a role for technology benchmarks; who will verify performance and certify projects; what is a share of the proceeds; how will buyers find sellers; who will run the store? Signs of progress came out of the fourth Conference of the Parties in Buenos Aires in 1998, the most important of which was a timetable to resolve the practical issues by the sixth Conference of the Parties in 2000.

International Trade and Industry Impacts of the Kyoto Protocol

W. David Montgomery, Charles River Associates

According to Dr. Montgomery, any limits on emissions trading will seriously harm the U.S. economy and industry. Global emissions trading has great potential to mitigate the costs of implementing the Kyoto Protocol. Costs could be reduced by 75 percent or more through global trading, but only if the United States is able to purchase permits to cover 80 to 90 percent of its required annual emissions reductions on a continuing basis. Unless global trading includes nearly all developing countries, there are likely to be significant impacts on U.S. trade and competitiveness. If China and India are not full partners in the Protocol and trading, harm to U.S. industries will remain significant.

Without global trading, permanent disparities between Annex I and non-Annex I countries will be created, and Annex I energy prices will rise while non-Annex I prices will fall, with consequent risks for U.S. trade and competitiveness. U.S. agriculture, chemicals, and other energy-intensive industries will be harmed even with Annex I trading by between 2 to 4 percent of sales. Investment and growth in chemicals and other intensive industries are likely to shift from Annex I countries to non-Annex I countries. Leakage, the migration of business activity from Annex I countries to developing countries, is not significantly reduced by Annex I trading—full global trading is required. Commitments to larger emissions reductions in future budget periods could increase economic losses and trade impacts by 50 percent or more. Developing country participation without China and India and the Clean Development Mechanism do not noticeably reduce losses to the U.S. economy. Finally, restrictions on carbon permit trading which have been proposed by Europe are as bad as no trading at all.

Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity

Susan H. Holte, Energy Information Administration

This paper summarized the major findings of the EIA analysis of the Kyoto Protocol.[1] Because the exact rules that would govern the final implementation of the Protocol are not known with certainty, the specific reduction in energy-related emissions cannot be established. The EIA analysis includes six cases that assume a range of energy-related carbon emissions reductions in the United States, varying from 24 percent above 1990 levels to 7 percent below 1990 levels. Each case was analyzed to estimate the energy and economic impacts of achieving the assumed level of reductions domestically. In each case, the United States is assumed to meet its 7-percent net reduction in greenhouse gases; however, the various cases reflect different levels of offsets from carbon-absorbing sinks, other greenhouse gases, and international activities.

Among the major findings of the analysis, the carbon price required to achieve the assumed range of carbon reduction targets domestically varies from $67 a metric ton in 2010 to $348 a metric ton. The transitional costs plus minimum economic losses range from 1 percent of gross domestic product (GDP) to more than 4 percent of GDP. In each case considered, most of the carbon reductions occur in the electricity generation sector, through a combination of reductions in the demand for electricity, the use of more efficient generation technologies, switching from coal generation to new natural gas generating plants and renewable energy sources, and the life extension of existing nuclear plants. Similarly, the end-use demand sectors respond by efficiency improvements, fuel switching, and reductions in service demand. Overall, coal consumption is significantly reduced and the use of natural gas, nuclear, and renewable energy increases. Petroleum consumption is reduced but still remains a significant share of U.S. energy use due to the continued dominance of petroleum products in the transportation sector.

Analysis of Policies and Measures To Meet or Surpass the U.S. Kyoto Commitments

Stephen Bernow, Tellus Institute

Dr. Bernow presented an analysis of a suite of policies and measures to reduce U.S. carbon dioxide emissions, using a modified version of the National Energy Modeling System. The policies and measures were targeted in each sector to overcome market barriers to more rapid diffusion of advanced energy-efficient, renewable, and low-carbon technologies and resources, rather than a single approach such as a carbon tax or cap and trade system. The policies included: regulatory and tax initiatives for combined heat and power systems; research, development, and tax incentives for investment in new, more efficient equipment in industry; efficiency standards, such as a fuel efficiency improvement of 1.5 miles per gallon a year; carbon content standards, such as a 10-percent reduction in carbon from light-duty vehicles by 2010; research and development for cellulosic ethanol and demand management in transportation; market transformation and standards in buildings; a renewable portfolio standard (RPS) for nonhydropower renewables of 10 percent by 2010; 10-percent biomass co-firing by 2010; caps on sulfur dioxide, nitrogen oxide, and particulates; and a carbon intensity cap in the electricity generation sector.

The overall package achieves the carbon reductions with cumulative net savings of about $158 billion, expressed in present-value 1995 dollars, or levelized net savings of $17 billion (1995 dollars) per year from 1998 to 2010. Significantly, while the overall net savings were large, the policy package included a few measures that had net

[1]Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03 (Washington, DC, October 1998).

costs: 10-percent cellulosic ethanol in vehicle fuels, renewable RPS, and other policies for electricity generation. The marginal cost of the package of policies was about $56 a ton of carbon. The high marginal cost in an overall package with net savings affords a twofold opportunity to meet high carbon reduction goals and begin the process of technology diffusion, scale economies, and learning that will set the stage for lower costs in meeting the deeper reduction commitments that will likely be required in periods beyond the first commitment period of the Kyoto Protocol.

Impact of Asian Economic Crises on Oil Markets and the Economy

Moderator: G. Daniel Butler, Energy Information Administration

The world oil market was characterized by significant turbulence during 1998. Prices fell by one-third on average from 1997 to 1998. Influencing this downturn in prices was an unexpected slowdown in the growth of energy demand, especially in Asia. Significant reductions in gross domestic product were experienced in Korea, Thailand, and Malaysia. Depression, accompanied by political turmoil, struck Indonesia. The region's largest economy, Japan, went from slow or no economic growth to a decline. Although the Chinese economy continued to grow, it was hampered by a reduction in trade with neighboring countries. This session undertook to review the prospects for Asian economic recovery as well as the mid- to long-term impacts of the Asian economic crises on worldwide economies and the oil market.

World Outlook: Growing—and Ultimately Unsustainable—Imbalances

Nariman Behravesh, Standard & Poor's Data Resources Incorporated

According to Dr. Behravesh, several global vulnerabilities must be avoided in order to escape a worldwide economic recession. In the United States, the low personal savings rate and the ballooning current account deficit are economic liabilities. There are also arguments that the U.S. stock market is overvalued. In Europe, the United Kingdom and Norway could join Germany and Italy in a recession. In addition, the Euro currency is weak. In Japan, monetary policy has started to ease, but interest rates are still too high, and investors continue to be worried about government finances. The Japanese economy continues to shrink. In China, growth has slowed down but remains positive. Real interest rates are high, vast amounts of excess capacity exist, and a serious bad loan problem is pervasive.

There are signs that the financial markets have stabilized in the developing economies of Asia, but large capacity overhang and vulnerability to the problems in Japan and China will slow the recovery process. In Latin America, Brazil is expected to be in a fairly deep recession in 1999. If inflexible domestic fiscal policies continue to persist in key Latin American economies, a lengthening of the current crisis could occur. World economic growth is expected to remain positive over the next 5 years, but only slightly above 1 percent in 1999.

The Asian Economic Downturn, Oil, and the Vicious International Politics of Adjustment

Edward L. Morse, Energy Intelligence Group

The Asian economic recession is providing a comprehensive test of virtually every sector of the international petroleum market. Fallout will be felt in the operation of the market, in future investments, in industry structure, and in international petroleum politics. A misunderstanding about the determinants of oil prices inevitably results in cautious and unrealistic projections about future prices. The past has always been a terrible guide to the future and continues so today.

What are the upper and lower limits within which prices will fluctuate? The floor is dictated by production restraints of the low-cost producers. The ceiling is dictated by a combination of new technologies, the existence of strategic reserves, and surplus production capacities. Technology reduces both costs and time horizons but accelerates resource depletion. Industrial countries have largely insulated themselves from oil shocks, regardless of whether the shock emanates from a price collapse or a price escalation. Non-OPEC supplies are eventually going to stagnate and fall. The timetable for this decline is dependent on technology's ability to economically produce the vast deepwater resources of the Caspian Basin, offshore West Africa, the South China Sea, and the U.S. Texas Gulf.

The structure of the petroleum industry will be governed by the need to manage and minimize risk and the ability to secure less expensive capital. Oil companies will be larger and more balanced in their vertical integration but significantly more horizontally integrated as full-service energy companies.

Is the Drive to Electricity Restructuring Short-Circuiting?

Moderator: Scott Sitzer, Energy Information Administration

The restructuring of electricity markets continues to be a topic of much debate at both the national and State levels. State referenda that could have led to repeal of some restructuring initiatives were soundly defeated by voters in California and Massachusetts in 1998, leading some to conclude that a new round of restructuring was in the offing. The momentum for both local and Federal action seems to have slowed, however, as low-cost States reconsider the impacts of competition and competing bills at the Federal level languish in Congress. The objective of this session was to provide details on the experience in three Northeastern States—Pennsylvania, New York, and Massachusetts—which have moved ahead with electricity restructuring. Both the successes and pitfalls were discussed, providing listeners a representative picture of what other States can expect as they continue to deliberate this contentious issue.

Current Status and Future Steps for Electricity Restructuring in Pennsylvania

Aaron Wilson, Jr., Pennsylvania Public Utility Commission

The key to the success of Pennsylvania's competitive electricity market is consumer education. Pennsylvania has gone to great lengths to provide information to its consumers, especially those in the residential sector, in order to allow them to make intelligent decisions concerning their choice of electricity suppliers. More than 50 percent of the customers participating in the initial pilot program shopped for alternative suppliers, with half of those actually making a switch, a rate indicating that the program has had a large measure of success. Consumer education is believed to be a necessary ingredient to consumer acceptance of the new market regime. Less emphasis has been placed on educating larger customers—both commercial and industrial—both because they are more generally aware of the marketplace and because they have greater access to information from individual suppliers, given their greater importance in overall market share.

Pennsylvania's Electricity Generation Customer Choice and Competition Act was passed by the legislature in December 1996. One of the motivations for passage of the Act was the State's higher-than-average electricity prices. Partial competition, following the pilot program, began on January 1, 1999, with gradual phasing in of full retail competition over the next 2 years. Individual agreements concerning their restructuring plans have been made with each of the State's major electric utilities. Agreements with utilities were generally settled without litigation, as both the State and the utilities realized it was in their best interests to proceed expeditiously in the new regime. "Green power" packages are available under the program and have been chosen by some customers.

Transition charges to recover stranded costs are a part of the restructuring program, with a transition period of approximately 4 years. "Slamming," the unauthorized switching of some customers that has been a problem with long-distance telephone competition, was also addressed by the Commission. The difficulties of the competitive market have been illustrated by the fact that some suppliers withdrew from the residential market because they did not see how to make a profit. Overall, however, Pennsylvania's large market and aggressive consumer information program seem to be keys leading to the general success of its restructuring efforts.

Electric Competition in New York: Wholesale and Retail

Mark Reeder, New York State Department of Public Service

The restructuring of New York's electricity industry has proceeded through the auspices of its Department of Public Service, which has authority under the State's laws to open up its electricity and gas markets to competition. As a result, no further legislation was needed. The stated goals of the Public Service Commission, which oversees the Department of Public Service, in terms of restructuring were:

- Lowering rates for consumers
- Increasing customer choice
- Continuing reliability of service
- Allaying concerns about market power
- Continuing environmental and public policy programs
- Continuing customer protections and the obligation to serve.

As in Pennsylvania, agreements between the State and individual utilities are the key mechanisms for both wholesale and retail competition. Each agreement specifies that customers can now choose the energy services companies that will generate their electricity. The power is to be distributed to customers through their traditional utilities, which will remain regulated. The generation function is therefore to be separated from the transmission and distribution functions through divestiture. As of March 1999, Consolidated Edison had sold more than half of its generating capacity; Niagara Mohawk had sold more than 40 percent of its generating assets; and New York State Electric and Gas had sold almost 75 percent of its capacity. As a result, the concentration of generation assets in the eight largest holders in the State had shrunk from 92 percent before restructuring to 63 percent. Ultimately, New York utilities will be selling 70 percent of their generating capacity to nonutilities.

Other elements of restructuring agreements include: the original utility becomes the provider of last resort in the event that the customer chooses not to switch; nuclear plants remain regulated by the State; there is some sharing of stranded costs between ratepayers and stockholders to help reduce electricity rates; and public benefits continue, but at somewhat lower rates than before, except for low income programs, which may expand slightly. Next steps in the wholesale market restructuring include establishment of location-based marginal cost pricing, starting up an Independent System Operator during the first half of 1999, and completing the divestiture of generating plants.

Retail competition is also proceeding, but at a somewhat slower pace. Before restructuring, New York's average electricity prices exceeded the national average by more than 50 percent. The main drivers were State and local taxes, uneconomical purchased power contracts, high operating costs, and the high cost of nuclear plants. Through approved settlements between the Commission and the utilities, rate reductions have been negotiated on the order of 25 percent for large industrial consumers and about 10 percent for all others. As of February 1999, only a small number of customers—about 95,000 out of a base of 7 million—had actually switched suppliers, but full phase-in of retail choice will not be complete for the largest utilities until the middle of 2001. The next steps in restructuring the retail market include public outreach and education to ease implementation; deciding what services, such as billing and metering, should be offered competitively; unbundling of those services: and looking at alternatives for making the local utility the provider of last resort.

Status of Electric Restructuring in Massachusetts: How the Market is Developing and What the Future Holds

Thomas Bessette, Massachusetts Department of Telecommunications and Energy

The goals of electricity restructuring in Massachusetts are to lower rates in the near term by 10 to 15 percent and to create a robust competitive market in the long term, with divestiture, corporate restructuring, and standards of conduct. The Electricity Restructuring Act of 1997 mandated customer choice of generation suppliers as of March 1, 1998, along with an average 10-percent rate reduction. Net stranded costs, after full mitigation, are to be fully recovered. Small municipal utilities were exempted, unless they choose to compete. Traditional public benefits were maintained, including preservation of low-income rate subsidies, increased funding for energy efficiency, and increased funding for renewable energy. The Act also called for consumer education in helping customers to make choices.

Currently, a number of actions are being taken, all of which are to be completed by the beginning of 2000. These include certification of stranded costs through comprehensive audits, determination of the cost of wholesale power contracts and whether or not they can be renegotiated, divestiture of generation assets, and studying the feasibility of competitive metering, billing, and information systems. To date, plans approved by the Department of Telecommunications and Energy include those for Boston Edison, Commonwealth Electric, and Massachusetts Electric. There are also merger and acquisition applications pending, including one involving a merger of Boston Edison with Commonwealth Energy System.

Interaction with the Independent System Operator (ISO) is a key ingredient of restructuring in Massachusetts and throughout New England. The role of the ISO is to ensure efficient markets and reliability. Questions have been raised about the independence of the ISO and the implications of that independence for customers.

Future issues for Massachusetts include performance-based ratemaking for distribution companies and the impact of Federal legislation on the workings of the State's newly deregulated electricity and natural gas markets. Federal legislation is needed because electricity is at least a regional, and ultimately a national, market and also to effect reform of the Public Utilities Holding Company Act and the Public Utilities Regulatory Policies Act, both of which may be at odds with much of the change in the rules and regulations now being promulgated by the States to increase wholesale and retail electricity competition.

Emerging Transportation Technologies

Moderator: David Chien, Energy Information Administration

The three topics for this session were emerging technologies in the Partnership for a New Generation of Vehicles (PNGV) program, advances in conventional technologies vs. alternative-fuel technologies, and environmental concerns and efficiency improvement. The National Research Council, which reviews the PNGV program annually, suggested in their last report that PNGV needs more funding and may not reach its *fuel efficiency goal of 80 miles per gallon with the vehicle cost and performance goals. Several technologies, such as fuel cells, electric hybrids, and direct injection for conventional vehicles, have been chosen by PNGV to meet its goals. Both diesel electric hybrid and the direct injection technologies, including gasoline and diesel versions, may have difficulty meeting future nitrogen oxide and particulate standards that are currently being determined by the U.S. Environmental Protection Agency through Clean Air Act Tier II emissions standards.*

Due to the lack of funding and the enormous costs of advanced research and development, the question remains whether more effort should be placed on conventional advanced technologies or on alternative-fuel technologies. They have different potential for reducing future carbon emissions. Increasingly, environmental issues appear to be the main drivers for increasing fuel efficiency, although they may not remain as such. With flat fuel prices in the foreseeable future and rising income levels, it may be difficult to reduce carbon emissions and raise fuel efficiency levels. Current trends appear to be toward larger cars, light trucks, vans, and increasingly large sport utility vehicles. It is also questionable whether alternative-fuel vehicles can really assist in reducing carbon if most of the sales are flexible-fuel alcohol vehicles, which usually burn gasoline.

Making a Business Out of It

William Ball, General Motors Corporation

Making a business out of new technology requires not only technical feasibility but also commercial viability. In order to be successful in business, manufacturers must see their business the way their customers see it. A price utility theory curve illustrates that for any given level of vehicle price there is a corresponding utility from the use of the vehicles. As customers pay higher prices for vehicles, they expect higher utility from the vehicle. The difficulty is that customers are used to paying a core vehicle price for conventional technology. Any new technology must either provide additional benefits to justify a higher price or retain the level of utility but at the same core price. The objective of technology is to reduce costs so that consumers will not experience any dropoff in utility and no vehicle price increases above the core level.

Business leaders also must see their business through the eyes of their investors. With increasing risks there are greater returns. Investors expect high returns, but that can only happen if consumers purchase the technology. Higher risks without higher returns will not satisfy investors' needs. The strategy to fulfill the requirements of both customers and investors is for manufacturers to get down the cost curve. For increasing volumes of production, costs will decline, but not without technical breakthroughs in research and development as well. There are currently three generations of vehicle designs that will assist manufacturers in achieving those cost reduction goals. Although most customers believe that manufacturers are currently at the generation three goals, we are actually only at the beginning of the second generation of advanced technologies.

The Transportation Challenge to Reduce Oil Use and Greenhouse Gases

Richard Moorer, Office of Transportation Technologies, U.S. Department of Energy

What is conventional technology? Incremental improvements in conventional engines, such as diesel direct injection (CIDI) and gasoline direct injection (SIDI), modest weight reduction, and blended fuels, represent the set of conventional technologies that could be used to reduce greenhouse gas emissions. Advanced technologies include hybrid vehicles, electric vehicles, fuel cell power, and hydrogen and biomass fuels. CIDI, SIDI, and weight reduction could lead to a vehicle that increases fuel efficiency by 50 percent. Hybridization, regenerative braking, and weight reduction have the potential to produce a vehicle with two times the efficiency of a conventional vehicle. Hydrogen fuel cell technology, a 40-percent weight reduction, and regenerative braking could result in a vehicle with three times the efficiency.

There are three market considerations in the advancement of vehicle technology. First, consumer acceptance is the key to technology success. Second, evaluation must be made of vehicle cost, driving range, acceleration, luggage space, etc. Third, policies may be needed to influence consumer and manufacturer behavior. The U.S. Department of Energy's Office of Transportation Technologies has projected that advanced technology vehicles will capture approximately 65 percent of all vehicle sales by 2020, resulting in a reduction of transportation fuel consumption by 2 quadrillion Btu.

There are basically three strategies to reduce carbon emissions from light-duty vehicles: reduce the level of vehicle miles traveled (VMT), increase the fuel economy of new light-duty vehicles, and substitute low-carbon fuels, such as cellulosic ethanol, for petroleum-based fuels. Reductions in VMT can only realistically amount to about a 6-percent total reduction based on travel by trip purpose. Hypothetically, to reduce carbon emissions by 50 million metric tons in 2010, new car efficiency would have to be approximately 47.4 miles per gallon and new light truck efficiency about 31.5 miles per gallon. To achieve a 100 million metric ton reduction, new car and new light truck efficiency would have to be 88.8 miles per gallon and 54.6 miles per gallon, respectively. Ethanol from biomass or cellulosic feedstocks has the potential to significantly reduce carbon emissions; however, there are supply constraints.

PNGV: The Next Five Years, Where We've Been, Where We Are, Where We're Going

Robert Culver, Ford Motor Company

The research strategy of the PNGV program can be categorized into three components: manufacturing, near-term conventional vehicles, and long-term next-generation vehicles. Manufacturing strategies are designed to reduce production costs and product development times for all car and light truck production. Near-term conventional vehicles can assist in pursuing advances that increase fuel efficiency and reduce emissions of standard vehicles. Long-term next-generation vehicles include a new class of vehicles with up to three times the fuel efficiency of today's comparable vehicle.

In 1995, technology areas for development were determined. Specific technology selections made in 1997. Concept vehicles will be available by 2000, and production prototypes will be ready in 2005. PNGV believes that 27 miles per gallon can be achieved by starting with current conventional technology. Reduction in mass or weight can add another 9 miles per gallon and aerodynamics an additional 6 miles per gallon, for a total of about 42 miles per gallon. Stratified charge direct injection of gasoline can add another 10 miles per gallon, and with a hybrid electric technology the fuel efficiency could potentially reach almost 64 miles per gallon. Another possible technology is compression ignition direct injection of diesel fuel, which could add 18 miles per gallon to the current 42 miles per gallon, including mass and aerodynamics, and another 12 miles per gallon in a hybrid electric configuration to reach a total efficiency of 72 miles per gallon. Alternatively, fuel cell technology could add another 38 miles per gallon to the base 42 miles per gallon.

There are several sources of uncertainty, including the additional mass of components (due to immature components and lack of parts integration). Other factors are mass compounding, unaccounted losses in installation and transient effects, vehicle aerodynamic penalties due to packaging and heat rejection, and fuel economy reduction as a result of emissions controls. On the positive side, future improvements in technology may reduce costs beyond the level anticipated.

The most promising technologies are light-weight materials; direct injection, which offers a 15- to 35-percent improvement in efficiency; electric traction, which permits electric hybrid and fuel cell propulsion; and proton exchange membrane fuel cells, which have the potential for low emissions and high efficiency. Light-weight materials have cost, safety, and joining problems which must be addressed. Electric traction has higher cost issues and also has complexity, high mass, and efficiency hurdles. Direct injection technologies must overcome problems with nitrogen oxide (NO_x) and particulate emissions, cost, and clean fuel infrastructure and availability. Fuel cells must deal with much higher costs, on-board fuel storage and processing, complexity, efficiency hurdles, packaging, higher mass, and fuel infrastructure problems. Some of these problems can be solved with lower sulfur fuel, which would reduce NO_x and particulate levels. Additional after-treatment with catalysts is another possible solution, but even when that is combined with low sulfur fuels, PNGV will have a very difficult time meeting the new Tier 2 emissions regulations formulated by the Environmental Protection Agency.

Challenges of an Expanding Natural Gas Market

Moderator: James M. Kendell, Energy Information Administration

The Annual Energy Outlook 1999 (AEO99) projects that U.S. natural gas consumption will increase to 30 trillion cubic feet by 2013 and 32 trillion cubic feet by 2020. Other industry participants believe that 30 trillion cubic feet will be exceeded even earlier, perhaps by 2010. The requirement under the Kyoto Protocol to reduce greenhouse gas emissions would place even more pressure on the natural gas market. In one case in the EIA analysis of the Kyoto Protocol, Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity, natural gas consumption rises to 35 trillion cubic feet in 2020. In 1998, U.S. natural gas consumption was just over 21 trillion cubic feet. The significant gap between current and projected consumption raises several questions about the availability of natural gas for a 30 trillion cubic foot market, the availability of pipelines to move the gas, and the costs and risks of industry expansion.

Infrastructure Requirements for a 30-Tcf Natural Gas Market

Anne V. Roland, Interstate Natural Gas Association of America Foundation, Inc.

In January 1999, the Interstate Natural Gas Association of America Foundation, Inc., released *Pipeline and Storage Infrastructure Requirements for a 30 Tcf U.S. Gas Market*. The purpose of the study was to create a realistic picture of what a 30 trillion cubic foot U.S. gas market might look like, by estimating the transmission and storage infrastructure requirements of the market and identifying the challenges facing the industry in supplying this infrastructure. The study was performed by Energy and Environmental Analysis with their Gas Market Data and Forecasting System. Two demand scenarios were created to simulate higher economic growth and higher gas use for electricity generation because of faster nuclear retirements and increased environmental restrictions on coal use. Two supply scenarios were created, increasing offshore Gulf of Mexico supplies and increasing onshore production, particularly in the Rocky Mountains.

In both demand cases, consumption exceeded 30 trillion cubic feet by 2010 and was met at a spot price of about $2.50 per million Btu (1998 dollars). Pipeline investment requirements were estimated to range from $30 to $32 billion between 1998 and 2010, and storage investment requirements were estimated to range from $2.2 to $2.4 billion. The study concluded that a 30 trillion cubic foot gas market is economically feasible by 2010 or shortly thereafter. The infrastructure requirements are substantial but within the levels achieved in recent years, and the challenges to the gas industry are manageable if the demand growth is steady and anticipated.

Access to the Natural Gas Resource Base: Trends and Opportunities

Robert J. Finley, Bureau of Economic Geology, University of Texas at Austin

Focusing on the ability of natural gas producers to meet the demand projected in *AEO99*, a 1997 Gas Research Institute study, *How Industry Has Increased Lower 48 Gas Production and Maintained Deliverability with Fewer New Wells*, was cited. This report notes that, since the mid-1980s, technology has increased production and the maintenance of deliverability with fewer wells, shifts to more productive regions have improved deliverability, and more recompletions have reduced decline rates. On the technology front, improved multi-channel, three-dimensional seismic data, combined with better processing and vastly improved, integrated interpretation systems, have allowed geologists to visualize reservoirs. This has led to a recognition of reservoir heterogeneity, increased reserve growth, and allowed drillers to address more specific targets.

Shifts to more productive regions include Norphlet sandstone in the Gulf of Mexico, deepwater Gulf of Mexico, and coalbed methane in the San Juan Basin. Targeted recompletions have improved reserves added per well. Forty-eight percent of increased production between 1986 and 1993 resulted from increased recompletions. The strongest areas for recompletions were the key producing regions of the Gulf Coast, both onshore and offshore, with established infrastructure. Due to the current economic conditions in the industry, jobs would be lost, mergers would occur, companies would go out of business, and expertise would be lost to the industry. However, more conservative companies will survive to take advantage of declining drilling costs, the substantial resource base, and new technologies—both hard and soft.

Forecasting the Future of Natural Gas: An Uncertain Endeavor

Philip M. Budzik, Natural Gas Supply Association

This talk opened with the caution that: “Not only were our forecasts wrong 20 years ago, they were totally and completely wrong.” Unlike the predictions of the late 1970s, resources are abundant and the Asian economies are suffering a severe economic recession. Nevertheless, future natural gas prices may be much more volatile than anyone expects. As a result, prices will be higher and consumption lower, all else being equal. The industry has little experience with gas commodity markets, and in other commodity markets, small imbalances in supply or demand can result in large price swings. Price volatility adds to the cost of doing business, and gas producers can be expected to require higher prices than if prices were expected to remain relatively constant. Current rates of return do not justify the investments made by gas producers. In other words, gas producers would probably have invested considerably less in gas production if they had been more prescient regarding gas commodity prices. As gas producers become more aware of the risks they face and begin to require higher rates of return, wellhead prices should rise or consumption should fall.

Electricity Issues in a Competitive Environment

Moderator: Robert Eynon, Energy Information Administration

The electricity transmission network is a key component in the restructuring of electricity markets. Issues related to ownership, operations, and system expansion need to be addressed as part of the market design. Ancillary services that were previously provided as part of the bundled services under regulation need to be defined and provided for as part of the restructuring process. Concerns have been raised about the potential for exercise of market power, particularly during periods of peak demand when lines are congested. This session explored what recent experience has revealed about these issues, policy considerations that are being formulated, and structures that could be implemented to facilitate efficient operations in the marketplace.

Reliability and Market Power

James Bushnell, University of California Energy Institute

Reliability has a special importance in electricity markets because, unlike other commodities, electricity needs to be produced when it is demanded and cannot be stored to any great extent. The inability to store electricity can lead to the exercise of market power. This opportunity exists because the operation of the electrical system requires substantial amounts of backup capacity in order to ensure reliable operations. For example, operational requirements require that some generators be dispatched even if their costs are higher than other generators located elsewhere in the network. Owners of transmission systems can also exercise market power where lines are congested. When congestion occurs, owners can command prices that are higher than they would be if lines were loaded below their maximum ratings. In this case, transmission providers have an incentive to forestall expansion of the network in order to maintain prices. Policymakers need to design market rules that mitigate the potential for market power and assure that prices are consistent with the costs of providing transmission services.

Ancillary Services: Directions and Possibilities

William Meroney,
Federal Energy Regulatory Commission

Until recently, ancillary services were bundled with energy generation services provided by regulated electric utilities. These services include backup power, cold start capability, and voltage support. With the advent of competitive markets for generation services, it is necessary to address market designs that provide these services explicitly.

Ancillary services have to be identified in order to develop such a market design. Currently, the Federal Energy Regulatory Commission and the North American Electric Reliability Council, which is charged with maintaining the reliability of the electrical system, have identified different ancillary services. Consistent definitions will need to be agreed upon in order to develop market structures to provide ancillary services. One approach is to allow the market to determine, on an *ad hoc* basis, which ancillary services need to be unbundled. This approach is attractive in minimizing the transaction costs in the provision of these services but suffers from the possibility of breaches in reliability in the delivery of electricity to customers. Ancillary services have public good aspects, and market responses may not be adequate mechanisms for providing them. Market-based pricing of ancillary services could require price caps to limit damages that could occur during disruptions. Mixed strategies are likely to evolve as markets develop. Market designs need to focus on making progress toward competitive markets, minimizing adverse impacts during transitions, and providing responsible and responsive governance.

Transmission Pricing in a TransCo World: Incentives for Efficient Operations and Long-term Investment

Richard Tabors,
Tabors, Caramanis & Associates,
Massachusetts Institute of Technology

TransCos are for-profit corporations that own or lease transmission systems. TransCos will be responsible for the operation of the grid and will be subject to regulation. Regulators will determine returns to investors based on performance. TransCos will also be responsible for mitigating congestion on the transmission grid by making investments in new facilities. The concept of TransCos is not new. Worldwide, there are existing and proposed TransCos.

The pricing method used to provide transmission service is currently being debated. One method is zonal pricing, which uses a fixed rate for broad geographic areas. Another method is nodal pricing, which specifies a tariff from one point to another point in the network. Zonal pricing is preferred to nodal pricing because players have information *ex ante* rather than *ex post* when nodal pricing methods are used. Financial instruments can be used to protect against congestion costs. For example, transmission capacity can be secured in advance by conducting auctions. In order to operate markets smoothly during the transition period, a direct allocation process could be used to accommodate existing contract obligations and native load commitments while employing auctions to allocate the balance of available capacity.

Renewables in a Carbon-Constrained World

Moderator: Thomas W. Petersik,
Energy Information Administration

Focusing on hydroelectricity, biomass, and wind, this session highlighted important issues affecting either the quantities of natural resources available for electricity generation or the use of renewable energy technologies in U.S. electric power markets. The session highlighted the ability of renewable energy supplies to meet increased demand, such as might occur in meeting possible U.S. carbon reduction requirements.

Congress and other interested parties frequently ask EIA to assess renewable energy under potential requirements to sharply decrease U.S. carbon emissions. In 1997, EIA examined proposed U.S. renewable portfolio standards, which included prospective reductions in carbon emissions. In 1998, EIA was asked by Congress to analyze the Kyoto Protocol and *examined a range of scenarios for reducing U.S. carbon emissions. More recently, EIA was asked to analyze the impacts of the Climate Change Technology Initiative, which included proposals to increase the contribution of renewables and reduce carbon emissions. Conventional hydroelectricity, biomass, and wind are among the likely renewable choices in a carbon-constrained environment.*

Hydropower— Where Do We Go From Here?

Richard T. Hunt, Richard Hunt Associates, Inc.

Hydroelectric power has been a mainstay of U.S. electric power throughout the 20th century, with more than 75,000 megawatts providing around 10 percent of all U.S. electricity supply. Hydropower is especially significant in the U.S. Northwest and in California, with more than 80 percent of the State of Washington's electricity supply supplied by hydroelectricity. Hydroelectricity affords some of the Nation's lowest electricity rates. Whereas States with lower percentages of hydropower, like New Hampshire and New York, have retail electricity prices in excess of 10 cents per kilowatthour, States with high proportions of hydropower, like Idaho and Washington, have some of the lowest, closer to 4 cents per kilowatthour.

U.S. hydroelectric generating capacity is not increasing and is likely to decline, despite projected demands for as much as 300,000 megawatts of new generating capacity through 2020 and 30,000 megawatts of undeveloped hydroelectric potential, more than 70 percent of it at existing dams. Although nearly 1,500 megawatts of new capacity were added from 1987 through 1990, only around 500 megawatts were added from 1991 through 1994 and less than 100 megawatts in 1995 and 1996. Hydroelectric power growth is being slowed by increased project relicensing costs and reductions in relicensed hydropower project output. Relicensing costs for smaller projects (5 megawatts or smaller) averaged barely half a million dollars in 1987, but by 1997 the costs had nearly doubled, to more than a million dollars. For projects in excess of 100 megawatts, relicensing costs have also more than doubled, from less than $2.5 million in 1987 to $5 million in 1997. Relicensed facilities are also suffering losses of effective generating capability, about 2 percent for smaller projects and 3 to 5 percent for larger projects.

Prospects for future U.S. hydroelectric expansion would be greater if: conflicts between State and Federal licensing requirements and procedures were resolved; the Federal Energy Regulatory Commission were the final authority in licensing decisions; consistent technical evaluation criteria existed to evaluate hydroelectric projects; and improved hydropower resource data and new hydroelectric generating technologies were supported. Licensing exemptions for small projects at existing dams would also speed additions of new hydroelectric generating capacity.

Biomass Resources in the United States—Potential Quantities and Prices

Marie Walsh, Oak Ridge National Laboratory

Recently there has been growing interest in biomass as an energy source. Global climate change concerns are a major reason, but biomass has other advantages, such as being a domestic energy source and its development potential in rural areas. Biomass resources can be categorized as follows: forest resources, agricultural residues, mill residues, and urban wastes in the current mix, with dedicated bioenergy crops a distinct potential source. Estimates of the quantities of each type and their price ranges have been provided to EIA.

Forest residues include logging residues and rough, rotten, and salvable dead trees. Quantities for each timber class are adjusted by site slope, accessibility, and retrieval efficiency. Costs, including collection, stumpage, and transportation, range up to $60 a ton for up to 38 million dry tons. Polewood (merchantable growing stock) is not included because of its higher value uses, but it could potentially add another 34 million dry tons at prices under $50 a ton.

Agricultural residues include numerous crop residues, primarily corn stover and wheat straw. The quantities of crop residues are generally halved to account for what must be left to sustain soil quality. Prices range up to $46 a ton for as much as 143 million dry tons, accounting for collection, transportation, and profit to the farmer.

A U.S. Forest Service survey of saw, pulp and paper, and veneer mills is used to develop quantities of primary mill residue by type (bark, fine residue, coarse residue) and use (fuel, fiber, and other). The data include only the material not used on site. Anecdotal evidence suggests that delivered prices are $10 to $20 per dry ton for unused residues and $20 to $30 per dry ton for residues used for fuel. Urban wood waste is that wood contained in municipal solid waste, including yard trimmings, and in construction and demolition debris. Quantities are based on estimates of the waste stream and an estimate of the share that is wood. Prices are very low or even negative.

Although dedicated bioenergy crops are not currently available, potential supplies were projected in a joint project between Oak Ridge National Laboratory and the U.S. Department of Agriculture. POLYSYS, an agricultural model developed and maintained by the University of Tennessee, was modified to include three potential crops—switchgrass, hybrid poplar, and willow. The model includes all major crops, a livestock sector, and various demands, including exports, for 305 statistical districts, which can be aggregated into States or regions. The analysis is limited to acres in current crop production, i.e., no Conservation Reserve Program lands. Expected prices, costs, and yields determine profits, which are the basis for allocating acres of production. The great majority of the energy crop acreage is devoted to switchgrass.

Accessing U.S. Wind Resources

Walter D. Short, National Renewable Energy Laboratory

The issue of U.S. wind resource availability is an important one, particularly in cases calling for increased U.S. renewable energy use. As a result, both actual wind resource availability and also EIA's representation of wind availability in NEMS become important. Recently released EIA analyses, for example, forecast different future U.S. wind capacities, depending upon aggregate demand, costs of alternatives, and assumed legal requirements for renewable energy use. Reexamination of the modeling suggests that EIA may be underrepresenting opportunities for future U.S. wind supply in scenarios that offer large demand for renewable sources.

In the EIA analysis, a number of constraints are imposed on wind capacity growth. Wind technology capital costs can increase by as much as 200 percent as greater proportions of regional wind resources are consumed. To represent the costs of supply bottlenecks, wind power capital costs increase in any year when the annual rate of U.S. capacity growth in orders for new capacity exceeds current capacity by more than 20 percent. Total wind capacity in any region is also limited, permitting a maximum addition of 1,000 megawatts per region per forecast year and limiting intermittent generators' (wind and solar photovoltaic) total regional share to no more than 10 percent of all electricity generation.

These constraints serve to limit U.S. wind power growth in some cases. They do not affect U.S. wind power growth in EIA's reference case forecasts; however, they overrestrict wind power growth under circumstances of greatly increased demand for renewables, such as in carbon reduction cases. Test results indicate that removing any one constraint may not greatly increase the results, so long as other constraints remain in force.

According to Mr. Short, in concept EIA's constraints on wind power are reasonable, but test runs and reexamination of the assumptions suggest that actual wind resources may be larger than assumed by EIA. More recent reexamination of wind resource data for the Pacific Northwest National Laboratory indicates that some excellent wind sites are not included in standard databases currently used by EIA. Additional analysis also suggests that EIA should consider allowing increased interregional electricity trade. As a result, future U.S. wind power supply responses may be underestimated in cases of high demand for renewable energy.