DOE/EIA-0607(97)
Distribution Category UC-950

Issues in Midterm Analysis and Forecasting

1997

July 1997

Energy Information Administration
Office of Integrated Analysis and Forecasting
U.S. Department of Energy
Washington, DC 20585

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Preface

Issues in Midterm Analysis and Forecasting 1997 (*Issues*) presents a series of seven papers, which cover topics in analysis and modeling that underlie the *Annual Energy Outlook 1997* (*AEO97*), as well as other significant issues in midterm energy markets. *AEO97*, DOE / EIA-0383(97), published in December 1996, presents national forecasts of energy production, demand, imports, and prices through the year 2015 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 *AEO97* and other analytical products of EIA's Office of Integrated Analysis and Forecasting. This provides public access to analytical work done in preparation for the midterm projections and to other unpublished analyses.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 *AEO97* 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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"The Impact of International Learning on Technology Cost"
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"The Possible Impacts of Electricity Futures on Forecasting Competitive Electricity Markets"
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"Forecasting Annual Energy Outlook Coal Transportation Rates"
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"*Annual Energy Outlook* Forecast Evaluation"
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"National Energy Modeling System / Annual Energy Outlook Conference Summary"
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Issues will be available on the July release of the EIA CD-ROM and on the EIA Home Page on the Internet (*http://www.eia.doe.gov*) by mid-July. *AEO97*, the assumptions underlying the *AEO97* projections, and tables of regional and other detailed results from the *AEO97* forecasts are also available on the CD-ROM and on the EIA Home Page. Forecast tables for the *AEO97* reference case are also available through EIA's Fax-on-Demand system (202/586-3550) and on diskette by contacting the Office of Scientific and Technical Information at 423/576-8401 or P.O. Box 62, Oak Ridge, TN 37831. *The National Energy Modeling System: An Overview*, DOE/EIA-0581(96), 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.

For ordering information on EIA publications and for questions on other energy statistics available from EIA, please contact EIA's National Energy Information Center. The address, telephone numbers, and hours are as follows:

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Sensitivity of Energy Intensity in U.S. Energy Markets to Technological Change and Adoption

by
Andy S. Kydes

*The Annual Energy Outlook 1997 (*AEO97*)*[1] *presents mid-term forecasts of energy prices and quantities to the year 2015. The forecasts were generated by the National Energy Modeling System (NEMS), a computer-based, energy-economy modeling system of U.S. energy markets. Underlying the forecasts are assumptions about the speed and scope of technological change in energy supply and manufacturing, as well as the rate at which new and improved technologies are adopted. This paper presents the results of a study in which 11 sets of different assumptions about technological change and adoption were used to prepare alternative forecasts for comparison with the* AEO97 *reference case. Technology cases developed in the* AEO97*, as well as other case definitions, were combined to provide feedback between sectors based on fuel prices and quantities. This report is a sequel to a pilot study*[2] *on the potential impact of technological progress on the U.S. economy and environment; it borrows heavily from that study—language, important insights, and conclusions—but is as self-supporting as practicable. The assumptions analyzed in the study were developed by the Energy Information Administration and are not based on U.S. Government research and development programs or their funding levels. Although progress has been made in "levelizing" technological optimism across the energy sectors, the levels of optimism may not be completely consistent across all sectors.*

Introduction

This paper examines the sensitivity of the *AEO97* projections to alternative technological assumptions. The non-integrated (standalone) technology analysis done in *AEO97* for demand provides a good first-order estimate of the impact of changes to the technology menu on energy consumption, since fuel prices in that analysis were unchanged from the reference case. The non-integrated technology analysis done in *AEO97* for supply provides a good first-order estimate of the impact of changes to the technology menu on fuel prices, with demands unchanged from the reference case. However, changes in energy consumption affect prices, which have feedback effects on the rest of the energy system. When the analytical framework is not integrated, the potential interactions and rebound effects between energy research and development programs and technologies may not be adequately accounted for. Consequently, any assessment of the benefits of achieving technological goals should be developed by using an integrated, technology-rich framework to assure consistent accounting and to capture the interactions between different sectors of the U.S. energy economy.

Background: The Pilot Study

In the pilot study, a series of sensitivity cases, also referred to as "standalone technology cases,"[3] were analyzed to examine the impacts of alternative assumptions regarding technology. Each case examined the sensitivity of a single module in NEMS to changes in the technology assumptions of that module, all else being the same as in the reference case. In a standalone case, only one module of NEMS is active. In the "integrated" cases described below, all the NEMS modules (the entire energy system) responded to

[1]Energy Information Administration, *Annual Energy Outlook 1997*, DOE/EIA-0383(97) (Washington, DC, December 1996).

[2]E. Boedecker et al., "The Potential Impact of Technological Progress on U.S. Energy Markets," in Energy Information Administration, *Issues in Midterm Analysis and Forecasting 1996*, DOE/EIA-0607(96) (Washington, DC, September 1996), p. 1.

[3]Energy Information Administration, *Annual Energy Outlook 1996*, DOE/EIA-0383(96) (Washington, DC, January 1996), pp. 261-268. "Standalone cases" or "side cases" use the individual modules of NEMS without feedback from any of the other NEMS modules.

changes in technology assumptions in any part of the energy system—i.e., markets were able to interact in the integrated cases.

Two sets of market and technology assumptions were defined for each energy sector to illustrate uncertainty in those markets. In the pilot study, the series of slow technology assumptions from the *Annual Energy Outlook 1996* (*AEO96*) were combined to form an integrated slow technological progress case.[4] The more optimistic group of sensitivity assumptions were also combined to form an integrated rapid technological progress case. The slow technological progress case examined fuel and technology choices when the availability or adoption of new technologies was assumed to occur at a slower rate than assumed in the *AEO96* reference case in all energy markets. The rapid technological progress case examined fuel and technology choices when the availability or adoption of new technologies was assumed to occur at a faster rate than in the *AEO96* reference case.

Although advanced cost and performance characteristics of technologies were represented in the pilot study, no attempt was made to analyze the potentially best technologies achievable through research. Also, the study did not incorporate all possible new technologies or the greatest possible improvements in new technologies. The goals of that analysis were (1) to analyze the potential role of technological progress on energy supply, consumption, and prices in U.S. energy markets and (2) to assess how "success" on one side of the supply or demand equation may reduce the potential benefits on the other side. "Success" for end-use demand in the optimistic case of the pilot study meant that consumers were more willing to purchase high-efficiency equipment that required longer payback periods than in the *AEO96* reference case. Success in the electricity generation markets was reflected by earlier availability of advanced technologies, lower perceived risk and risk premiums, and faster "learning-by-doing," which can lower costs to the mature state sooner. For oil and gas production, success was represented as faster rates of drilling cost reduction and expansion of the resource base. For coal, success was represented as higher labor productivity rates.

Slower technological progress was typically represented for demand by freezing the menu of technologies to that available in 1995. For electricity generating technologies, advanced technologies become available later in the forecast, at higher cost, and with slower learning (i.e., more cumulative capacity was required to achieve the same cost reductions achieved in the *AEO96* reference case).

The Sequel

The study reported in this paper attempted to improve upon the pilot study and extend its results. First, the autonomous change assumptions in the "slow" and "rapid" transportation cases of the previous study were replaced by technological menus (availability, cost, and performance) that varied according to the "technological optimism" in each case, consistent in concept with the technology treatment in the residential, commercial, and electricity markets. Second, sensitivity cases were examined for the residential and commercial markets, varying the "hurdle rates"—the willingness to purchase higher efficiency equipment with higher capital cost. The sensitivity cases tested the impact of changes in the menus of technologies relative to changes in the willingness of consumers to purchase greater efficiency at higher cost.

"Hurdle rates" in the residential and commercial markets can be thought of as the sum of two components: a cost-of-money component and a nonfinancial component that reflects all other factors that influence consumer choices. Two cases were run relative to the residential and commercial sector hurdle rates assumed in the *Annual Energy Outlook 1997* (*AEO97*) reference case. In the first case, the nonfinancial components of hurdle rates were reduced to 50 percent of their reference case values. In the second group of cases, the nonfinancial component was reduced to 0 percent. The financial portion of the hurdle rate was assumed to be 15 percent for residential and commercial customers in all cases. In *AEO97*, hurdle rates in the residential sector varied by technology, from 15 percent for space-conditioning equipment to 200 percent for oil-burning water heaters. In the commercial sector, hurdle rates ranged from 18 percent to more than 200 percent, for different customer classes and end uses.

A third change in this study was that, in sectors where technologies were explicitly represented (residential, commercial, transportation, and utilities), costs for advanced technologies were generally reduced by similar percentages (35 percent) over a 15-year period for the rapid cases. For coal and for oil and gas supply, the technology, wage, and productivity parameters for the low and high technology cases were changed by one or two standard deviations from the expected values in the *AEO97* reference case (see below).

The cases or subcases that were used in the model runs for this study are summarized below:

Reference Case: A few of the *AEO97* reference case assumptions were adjusted to provide more price response to selective electricity end uses in the residential,

[4]Cases are "integrated" when all the NEMS modules provide feedback to changes in assumptions.

commercial, and industrial markets, which previously did not have them. The change was designed not to change the reference case but to allow short-term response in the event that large price swings occurred relative to the reference case.

Reference Case (50+15): This case used the technology assumptions of the reference case but assumed a 50-percent reduction in the nonfinancial hurdle rates in the residential and commercial sectors.

Reference Case (15): This case used the technology assumptions of the reference case but assumed a reduction to 0 percent in the nonfinancial hurdle rates in the residential and commercial sectors; that is, all the hurdle rates were reduced to 15 percent.

Slow Supply: The *AEO97* "slow supply technology" cases were grouped and run together. In this "slow supply" case, technology menus and characteristics in the utility sector were restricted to those available in 1996. The technology-related parameters for oil and gas supply were reduced by one standard deviation. Coal productivity and wage rates were changed by two standard deviations.

Slow Demand: The demand sectors used the *AEO97* "slow demand technology" assumptions; that is, the technology menus were restricted to those available in 1997. Building shell efficiencies were held at 1997 levels through 2015.

Slow Demand (15): This case used the same assumptions as the "slow demand" case but reduced the nonfinancial hurdle rates in the commercial and residential sectors to 0 percent; that is, all the hurdle rates were reduced to 15 percent.

Rapid Supply: The "rapid supply" technology case for utilities assumed that the initial optimism premium for advanced generation technologies was reduced by 50 percent and that learning continued past the original *n*th-of-a-kind cost, so that capital costs were 12 percent lower at maturity than in the reference case. Since learning (after the first-of-a-kind) can cause capital cost reductions for new technologies of about 25 percent in the reference case, the cumulative reduction to maturity in the rapid supply case is approximately 37 percent after learning begins. For oil and gas supply, one standard deviation above the expected values for the technology-related parameters was used. For coal, wage rates and productivity were changed by two standard deviations. An advanced, low-cost ethanol supply was added, which made ethanol available for use as an oxygenate, gasohol blending, and E85 at a cost that ranged from approximately $0.60 to $0.90 per gallon.

Rapid Demand: The "rapid demand" technology cases used the advanced technology cost reduction assumptions in *AEO97*. In the *AEO97* rapid demand technology cases, advanced residential and commercial technology costs declined by 35 percent over a 15-year period from their initial date of availability, and building shell efficiencies increased by 50 percent over the reference case. For transportation, incremental performance of advanced technologies improved by 33 percent, and incremental costs were 50 percent lower than in the reference case. In addition, a new technology, known as the Partnership for the Next Generation Vehicle (PNGV), was added to the menu of advanced technologies for light-duty vehicles. For the industrial sector, a change of one standard deviation from the historical trend was emulated.[5]

Rapid Demand (50+15): This case used the technology assumptions of the rapid demand case but assumed that the nonfinancial hurdle rates were reduced by 50 percent in the residential and commercial sectors.

Rapid Demand (15): This case used the technology assumptions of the rapid demand case but assumed that the nonfinancial hurdle rates were reduced to 0 percent in the residential and commercial sectors; that is, all the hurdle rates were reduced to 15 percent.

The industrial, coal, and oil and gas supply models in the National Energy Modeling System (NEMS)[6] do not represent individual technologies but use historically plausible technological progress rates to evaluate system impacts. Because technological change in the oil and gas, industrial, and coal markets was specified as autonomous change without explicit linkage to price causal factors in energy markets, the insights are somewhat limited with respect to technological impacts.

[5]The following assumptions represent the target of other levers in the model, which attempt to emulate the intended target: (1) for energy-intensive industries, increase the Technology Potential Curve (TPC) by a factor of 3; (2) for nonmanufacturing industries, reduce consumption by about 0.4 percent per year, such that by 2015 consumption is about 6 percent lower than in the reference case; (3) for nonintensive manufacturing, reduce consumption by about 0.15 percent per year such that by 2015 consumption is about 3 percent lower than in the reference case; (4) for asphalt feedstocks, reduce consumption by about 0.7 percent per year, such that by 2015 consumption is about 10 percent lower than in the reference case; (5) for natural gas feedstocks, reduce consumption by about 0.2 percent per year, such that by 2015 consumption is about 4 percent lower than in the reference case; and (6) for LPG feedstocks and petrochemical feedstocks, reduce consumption by about 0.35 percent per year, such that by 2015 consumption is about 8 percent lower than in the reference case.

[6]Energy Information Administration, *The National Energy Modeling System: An Overview*, DOE/EIA-0581(96) (Washington, DC, March 1996).

As stressed in the pilot study,[7] technological progress and rates of productivity improvement are factors that have often been underestimated by energy forecasters since the mid-1970s. Supply projections, with the exception of coal, have been dominated by depletion effects, and the resulting fossil fuel price projections have had high rates of growth—neither of which have been borne out by history. The rate of technological progress has historically far outpaced the potential depletion effects on U.S. domestic production, and technological progress has been the principal reason for the declining trend in natural gas prices over the past 15 years.[8] Coal prices have declined for a number of reasons, including (1) a shift in the geologic location of coal production, (2) a shift to surface mining and to larger mines, and (3) technology improvements. The rapid coal supply technology case represents the change in all factors influencing coal prices, not just technological progress, because it is difficult to separate them.

Recently, the apparent need for international mitigation of carbon emissions and the preparation of the U.S. Government negotiating position on carbon emissions for the planned meeting in Kyoto, Japan, in December 1997 have further focused attention on the potential role that advanced new technologies might play in carbon mitigation. The study of compliance with international carbon stabilization protocols has identified energy intensity as the common reference for carbon stabilization in the United States. International meetings and conferences on climate change consistently focus on the potential role of advanced technologies as the centerpiece of any carbon mitigation and climate stabilization strategy. Because of the current debate on carbon stabilization and mitigation, this paper examines the impact of technological progress on energy intensity and carbon emissions in the United States.

The following 12 integrated technology cases were examined in this study, using the assumptions described above for the cases and subcases: *(a)* reference case, *(b)* rapid supply/rapid demand case, *(c)* slow supply/slow demand case, *(d)* reference (50+15) case, *(e)* reference (15) case, *(f)* slow supply/rapid demand case, *(g)* slow supply/rapid demand (50+15) case, *(h)* slow supply/rapid demand (15) case, *(i)* rapid supply/rapid demand (50+15) case, *(j)* rapid supply/rapid demand (15) case, *(k)* rapid supply/slow demand case, and *(l)* rapid supply/slow demand (15) case.

All cases used the *AEO97* reference case world oil price assumptions, U.S. macroeconomic growth assumptions, and international market conditions. The detailed results of cases *(b)* and *(c)* are compared with the reference case in the appendix that follows this paper.

Although alternative technology assumptions were incorporated in the cases, and traditional discussion of the price, supply, and consumption impacts of the alternative technologies are presented, this report focuses on the impacts of available technological options and consumer choices on energy intensity by sector.

Energy Supply, Consumption, and Price Patterns

The reference case indicates where technological progress may proceed, given today's policies, consumer behavior trends, and other economic and non-economic conditions. The rate of technological progress toward higher efficiency and lower cost energy supply and utilization technologies and their rate of market adoption can have a profound effect on energy prices, energy consumption, and carbon emissions. Although technological progress for both the supply and demand technologies in the energy system can result in significant price reductions, the impacts of simultaneous technological progress for both supply and demand on prices are not additive.

Technological progress for supply technologies primarily reduces the cost of production and prices. Reduced production costs and prices improve the competitiveness of domestic energy industries, provide greater self-reliance on domestically produced energy supplies, and increase demand. Since energy constitutes less than 10 percent of the U.S. gross domestic product (GDP), reductions in energy prices have only a mild effect on positive economic growth and lower inflation rates (Table 1).

Technological progress for demand technologies primarily reduces energy consumption and, as a consequence, energy prices and carbon emissions. In general, however, individual technological successes and benefits are not additive, because of the energy-economic feedback effects and the interactions among energy decisionmakers across energy markets.

To illustrate, the 2015 natural gas price in the slow supply/slow demand technology case was $2.87 per thousand cubic feet. When rapid demand technological progress assumptions were combined with slow supply

[7]E. Boedecker et al., "The Potential Impact of Technological Progress on U.S. Energy Markets," in *Issues in Midterm Analysis and Forecasting 1996.*

[8]The relatively high gas prices of the 1995-96 and 1996-97 winter periods reflect seasonal temperature variations and a lack of experience by the gas industry in managing supply resources in a competitive market during unusually cold weather.

Table 1. U.S. Energy Indicators, 2015: Comparison of Alternative Cases

Key Indicators	1995	Reference Case	Rapid Supply/ Rapid Demand	Slow Supply/ Slow Demand	Rapid Supply/ Rapid Demand (50+15)	Rapid Supply/ Rapid Demand (15)	Slow Supply/ Rapid Demand (15)	Reference Case (15)	Rapid Supply/ Slow Demand	Slow Supply/ Rapid Demand
World Oil Price (1995 dollars per barrel)	17.26	21.13	18.24	23.26	18.25	18.25	20.88	21.00	20.11	20.88
Oil Imports (quadrillion Btu)	16.9	28.6	23.6	32.3	23.6	23.7	28.5	28.5	27.2	28.7
Oil Consumption (quadrillion Btu)	34.9	43.3	40.3	45.2	40.3	40.3	40.5	43.2	44.9	40.6
Natural Gas Wellhead Price (1995 dollars per thousand cubic feet)	1.61	2.09	1.31	2.87	1.28	1.26	2.34	1.98	1.60	2.44
Natural Gas Consumption (quadrillion Btu)	22.2	30.8	30.7	28.5	30.3	29.9	26.1	30.0	34.1	26.6
Coal Minemouth Price (1995 dollars per short ton)	18.83	15.57	12.12	20.28	12.13	12.21	18.36	15.21	13.35	18.32
Coal Consumption (quadrillion Btu)	20.0	23.9	21.6	29.5	21.6	21.5	25.6	23.3	22.9	26.1
Total Energy Consumption (quadrillion Btu)	90.9	110.9	105.3	116.3	104.7	104.3	104.8	109.3	115.0	105.9
Electricity Sales (billion kilowatthours)	3,008	4,005	3,828	4,152	3,758	3,726	3,736	3,871	4,146	3,836
Change in Residential Delivered Energy Intensity (percent per year)	NA	-0.19	-0.27	0.00	-0.28	-0.34	-0.53	-0.37	0.13	-0.45
Change in Residential Primary Energy Intensity (percent per year)	NA	-0.22	-0.32	0.13	-0.32	-0.39	-0.36	-0.38	0.00	-0.28
Change in Commercial Delivered Energy Intensity (percent per year)	NA	-0.01	0.00	0.04	-0.13	-0.18	-0.26	-0.23	0.13	-0.09
Change in Commercial Primary Energy Intensity (percent per year)	NA	-0.18	-0.21	0.09	-0.39	-0.42	-0.29	-0.45	-0.10	-0.07
Carbon Emissions (million metric tons per year)	1,424	1,798	1,690	1,941	1,680	1,672	1,731	1,770	1,837	1,753
Carbon Emissions per Capita (metric tons per year)	5.4	5.8	5.4	6.2	5.4	5.4	5.6	5.7	5.9	5.6
Gross Domestic Product (billion 1992 dollars)	6,739	9,881	9,925	9,833	9,926	9,927	9,869	9,881	9,901	9,866

Btu = British thermal unit.

NA = not applicable.

Reference case = adjusted *AEO97* reference case.

Note: Although 11 new cases were run, it is only necessary to display 9 to support the conclusions drawn from this table. All 11 new cases, as well as the *AEO97* reference case and standalone technology cases, are illustrated in Table 2.

Sources: Energy Information Administration, *Annual Energy Outlook 1997,* DOE/EIA-0383(97) (Washington, DC, December 1996), Tables A1, A4, A5, A19, and A20; and AEO97 National Energy Modeling System runs POLBASE.D032497A, ISS97HH.D032597A, ISS97LL.D032597A, ISS97HN.D032597A, ISS97H3.D032897A, ISS97L3.D032597A, ISS97B2.D032697A, ISS97HL.D032597A, and ISS97HL.D032597A.

technological progress assumptions (the slow supply / rapid demand case), the wellhead natural gas price in 2015 was projected to be $2.44 per thousand cubic feet in 1995 dollars (Table 1)—a price change of $0.43 per thousand cubic feet. Conversely, when rapid supply technological progress assumptions were combined with slow demand technological progress assumptions (rapid supply / slow demand), the 2015 wellhead gas price was $1.60 per thousand cubic feet—a price reduction of $1.27 per thousand cubic feet.

If the technological impacts had been additive relative to the slow supply / slow demand case, the price change would have been $1.70 per thousand cubic feet ($1.27

+ $0.43) and the gas price would have been $1.17 per thousand cubic feet in 2015 in the rapid supply/rapid demand case; however, the wellhead gas price was projected to be $1.31 per thousand cubic feet when rapid technological progress was combined for both supply and demand. The difference is due to the interaction of the energy markets and the "bounce-back" effect that lower energy prices have on demand. With lower fuel prices, gas consumption increases, moderating the potential price reduction. The results were similar for coal and oil.

Prices

World oil prices in the technology cases respond to changes in U.S. oil consumption and production patterns. Projected world crude oil prices in 2015 vary from $18.24 per barrel to $23.26 per barrel, a 28-percent change between the slow and rapid technological progress cases in response to differences in available supply and demand technologies. However, the international oil market was assumed to remain unchanged from the *AEO97* reference case. That is, the penetration of domestic oil and gas technologies into the international market was not represented, and the feedback effect of lower oil prices on international oil demand was not captured in these cases.

International gas markets have a limited influence on domestic U.S. gas prices. Natural gas does not have the international accessibility that international oil markets provide. Consequently, natural gas prices are more sensitive to domestic natural gas demand and to the quantities of economically recoverable resources available in the North American continent, which in turn are dependent on geology and the rate of technological progress. In 2015, natural gas wellhead prices were projected to range from $1.26 per thousand cubic feet in the rapid supply/rapid demand (15) case to $2.87 per thousand cubic feet in the slow supply/slow demand case, a 128-percent difference between the technology cases. Coal prices ranged from $12.12 per ton to $20.28 per ton, a 67-percent difference—or more than twice the difference in the world oil price projections—reflecting the influence of world oil prices on domestic prices. The pattern of electricity prices followed the pattern of fossil fuel prices.

Energy Consumption

Total energy consumption in the rapid technological progress case (rapid supply/rapid demand) was projected to be about 5 percent lower than in the reference case because of the penetration of advanced end-use technologies. When technological progress was assumed to be slower than in the reference case for both supply and demand technologies, fossil fuel prices in 2015 were projected to be substantially higher (natural gas at the wellhead was 37 percent higher, coal was 30 percent higher, and the world oil price was about 10 percent higher), and total fossil fuel consumption was about 5 percent higher than in the reference case, due largely to lower energy conversion efficiencies. Because the majority of energy-utilizing equipment is replaced slowly, depending on its physical life, the impact of technological change on energy consumption during the forecast period is gradual.

Electricity sales were greatest in the slow demand/slow supply technology case (4,152 billion kilowatthours) and lowest in the rapid supply/rapid demand (15) case (3,726 billion kilowatthours)—a difference of about 11 percent. The penetration of high-efficiency end-use equipment was at its highest when rapid demand (15) assumptions were used. Electricity sales were projected to be at their highest when end-use technology choices were limited to the menu available in 1997 (lowest end-use efficiencies) and consumer decisionmaking parameters were assumed to remain the same as in the reference case. In the slow supply/slow demand (and the rapid supply/slow demand) case, primary fuel consumption and electricity sales were at their highest, because fuel switching favors electricity in end-use markets. Electricity prices, which include fuel, operation and maintenance costs, and capital costs, increase less quickly than other fuel prices, and this results in greater electricity sales. The growth in electricity sales allows new gas combined-cycle and turbine units with lower capital cost than the stock of generation equipment to be built and causes the capital component of price to decline more quickly than delivered fuel prices increase—even relative to the reference case.

When the rapid demand technology case assumptions were used and the supply assumptions were varied (rapid supply/rapid demand versus slow supply/rapid demand), oil demand changed negligibly (an 0.7-percent increase) despite the 14-percent increase in the oil price. In the rapid supply technology case, lower oil and gas prices increased the demand for both oil products and natural gas in all demand sectors except industrial. In the industrial sector, the price differential between oil and gas was sufficiently large to cause some fuel switching from oil to natural gas and reduce the difference in oil consumption between the cases to only about 0.3 quadrillion British thermal units (Btu). The price change was far more significant for natural gas (about 86 percent) than for oil, resulting in a difference in natural gas consumption between the two cases of about 4.1 quadrillion Btu. Coal consumption lost the most, about 4.5 quadrillion Btu, when rapid supply technologies were assumed. Most of the coal losses occurred in the generation market due to competition with natural gas.

Supply technology assumptions affect the mix between domestic production and imports, whereas demand technology assumptions affect the level of oil consumption. When rapid demand technological progress was assumed relative to the slow supply / slow demand technology case, oil consumption was projected to be approximately 4.6 quadrillion Btu lower in 2015. When slow demand / rapid supply technology assumptions were used, oil imports were 5.1 quadrillion Btu lower than in the slow supply / slow demand technology case.

When rapid supply / rapid demand technological assumptions were used, oil imports were 8.7 quadrillion Btu lower in 2015 than in the slow technology case, representing additional displacement of oil imports by domestic oil production. Import oil dependence is minimized when rapid demand technological progress is combined with rapid supply technological progress, because rapid demand technological progress reduces the overall demand and thus the prices for delivered energy. Rapid supply technological progress reduces domestic exploration and production costs and prices (a direct result of technological impacts being restricted to domestic U.S. markets), making the domestic oil and gas industry more profitable. It can be argued that technological progress on the supply side would have greater impact on mature (high-cost) supply sources such as those in the United States than on low-cost producing regions such as those in the Persian Gulf. Oil imports were projected to range from 23.6 quadrillion Btu in 2015 in the rapid supply / rapid demand technological progress case to 32.3 quadrillion Btu in the slow supply / slow demand case.

Advances in supply technologies influence the tradeoff between oil imports and domestic crude oil production. Rapid supply technological progress assumptions result in lower domestic production costs and increased domestic oil production in 2015, which displaces oil imports, all else being equal. Slow supply technological progress relative to the reference case results in higher domestic exploration and production costs, reducing domestic oil production and increasing oil imports. Domestic oil consumption is determined primarily by transportation demand and that sector's technological progress assumptions, regardless of which supply technological progress assumptions are used. For example, domestic oil consumption hovered around 40.5 quadrillion Btu whenever the rapid demand technology assumptions were used, because international oil markets moderate the oil price variations. When the slow demand technological progress assumptions were used, U.S. oil consumption in 2015 was projected to be about 45 quadrillion Btu, regardless of which supply technological progress assumptions were used.

The rate of demand technological progress primarily affects consumption of fuels and fuel prices, whereas the rate of supply technological progress primarily affects fuel prices and domestic production. Consequently, fuel consumption is at its greatest when lower end-use efficiencies, which lead to higher fuel consumption, are coupled with higher supply efficiencies, which lead to lower supply prices and greater domestic supply. Similarly, fuel consumption, both in the aggregate and for each fuel, is at its lowest when end-use efficiencies are their highest. However, in the slow technology case, slow supply technological progress increased the price of natural gas faster than the price of coal—which is far more abundant domestically than natural gas—or oil, whose prices are moderated by international markets. Consequently, natural gas wellhead prices rose to $2.87 per thousand cubic feet in 2015, and natural gas lost market share primarily to coal for generation and to electricity in end-use markets.

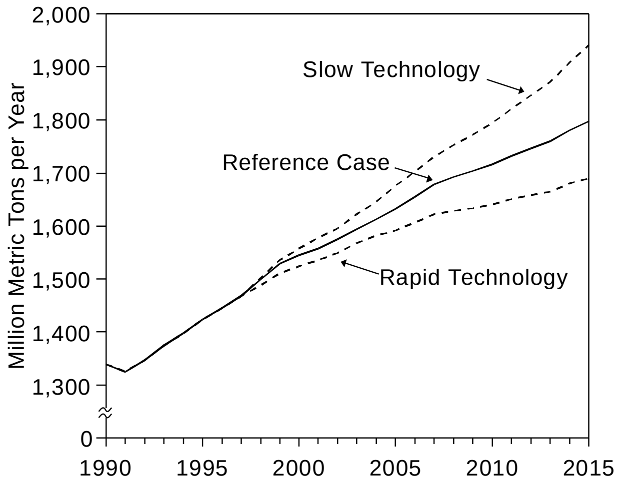
Natural gas consumption in 2015 ranged from 26.1 quadrillion Btu in the slow supply / rapid demand (15) technological progress case to 34.1 quadrillion Btu in the rapid supply / slow demand case, corresponding to natural gas prices of $2.34 per thousand cubic feet and $1.60 per thousand cubic feet, respectively.

Carbon Emissions

Carbon emissions are directly correlated with fossil fuel consumption. The reference case projected 1,798 million metric tons of anthropogenically generated, combustion-related carbon emissions in the United States in 2015, an average of 5.8 tons per person. In the rapid supply and demand technological progress case, carbon emissions were projected to reach about 1,690 million metric tons, or 5.4 tons per person. In the slow technological progress case, carbon emissions were projected to reach 1,941 million metric tons, or 6.2 tons per person. None of these cases achieved the 1990 emission levels of 1,344 million metric tons of carbon per year (Figures 1 and 2).

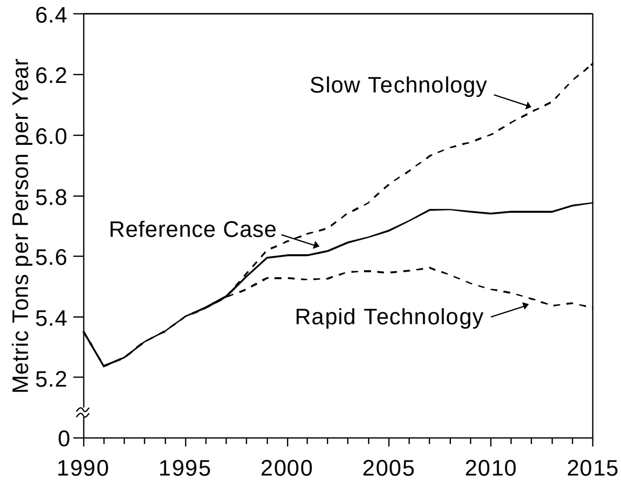
Although none of the cases examined achieved carbon stabilization despite the favorable assumptions made in the rapid technology cases, the results suggest that R&D investments that succeed in developing low-cost, high-efficiency end-use technologies and facilitate market acceptance of them could play a significant role in efforts to moderate carbon emissions in the United States. R&D programs that improve the availability and market acceptance of cost-efficient transportation technologies, coupled with successful oil and gas supply

Figure 1. Total U.S. Carbon Emissions, 1990-2015: Comparison of Three Cases



Source: Energy Information Administration, AEO97 National Energy Modeling System runs POLBASE.D032497A (reference case), ISS97HH.D032597A (rapid technology), and ISS97LL. D032597A (slow technology).

Figure 2. Per Capita U.S. Carbon Emissions, 1990-2015: Comparison of Three Cases



Source: Energy Information Administration, AEO97 National Energy Modeling System runs POLBASE.D032497A (reference case), ISS97HH.D032597A (rapid technology), and ISS97LL. D032597A (slow technology).

R&D programs, could have a significant impact on reducing dependence on imported oil.

Energy Intensity: The Roles of Technologies and Consumer Choices

Many energy and environmental analysts throughout the world are currently investigating alternative carbon mitigation protocol options and their potential impacts on economic systems, in preparation for the meeting of the parties in Kyoto, Japan, in December 1997. The principal mechanisms being investigated for achieving carbon stabilization goals include: (1) the potential role of successful R&D, which would provide improved menus of technologies that could reduce fossil fuel consumption; (2) technologies for carbon sequestration; (3) carbon trading; (4) imposition of efficiency standards in the residential, commercial, and transportation markets; and (5) in parts of Europe, carbon taxes. This section examines the potential impact of variations in hurdle rates and the availability of advanced technologies at lower costs than in the reference case on the rate of change in energy usage per household (residential sector) or per square foot of floor space (commercial sector).

Table 1 (above) illustrates how advanced technologies and consumer choices affect energy intensity in the residential and commercial energy markets. Table 2 illustrates the changes in energy intensities as a function of the assumed rates of technological progress. Figures 3 through 7 illustrate the time change of energy intensity for three of the principal cases (reference case, rapid supply/rapid demand, and slow supply/slow demand).

The principal factors that affect energy intensity are: (1) the availability, cost, and performance of technologies; (2) consumer preferences; (3) the physical life of equipment or equipment retirement rates; (4) the rate of household formation and new housing growth; (5) commercial floorspace and its rate of growth; (6) the mix and level of industrial output; (7) disposable income and new car sales; and (8) the level of energy demand. This study addressed only the first two factors through sensitivity analysis. Since the *AEO97* macroeconomic growth assumptions were used in all cases, energy service demand, industrial output, disposable income, commercial floorspace growth, and household formation were determined consistently across cases. For this study, premature retirements in the residential and commercial markets were assumed not to occur, because energy prices were determined to be too small to induce premature retirements.

Impact of Availability of Advanced Technologies Without Changing Consumer Behavior

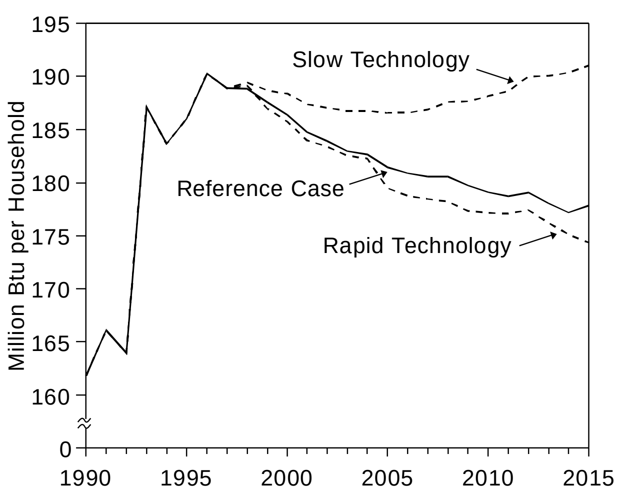
To investigate the issue of the role of technology alone, it suffices to investigate the changes in intensities brought about between the reference case, the rapid supply/rapid demand case, and the slow supply/slow

Table 2. Average Annual Rate of Change in U.S. Energy Intensities, 1995-2015: Comparison of Alternative Cases
(Percent per Year)

Cases Analyzed	Residential Sector		Commercial Sector		Industrial Sector		National Average	
	Delivered Energy Intensity	Primary Energy Intensity	Delivered Energy Intensity	Primary Energy Intensity	Delivered Energy Intensity	Primary Energy Intensity	Delivered Energy Intensity	Primary Energy Intensity
Reference Case	-0.19	-0.22	-0.01	-0.18	-0.99	-1.07	-0.81	-0.92
Rapid Supply/Rapid Demand	-0.27	-0.32	0.00	-0.21	-1.36	-1.48	-1.09	-1.19
Slow Supply/Slow Demand	0.00	0.13	0.04	0.09	-0.81	-0.78	-0.66	-0.65
Slow Supply/Rapid Demand	-0.45	-0.27	-0.09	-0.07	-1.39	-1.37	-1.16	-1.14
Slow Supply/Rapid Demand (50+15)	-0.46	-0.28	-0.21	-0.26	-1.39	-1.37	-1.18	-1.17
Slow Supply/Rapid Demand (15)	-0.53	-0.36	-0.26	-0.29	-1.40	-1.38	-1.20	-1.19
Rapid Supply/Rapid Demand (50+15)	-0.28	-0.32	-0.13	-0.39	-1.37	-1.48	-1.12	-1.22
Rapid Supply/Rapid Demand (15)	-0.34	-0.39	-0.18	-0.42	-1.37	-1.49	-1.13	-1.24
Reference (50+15)	-0.26	-0.27	-0.13	-0.35	-1.00	-1.07	-0.84	-0.95
Reference (15)	-0.37	-0.38	-0.23	-0.45	-1.00	-1.07	-0.86	-0.99
Rapid Supply/Slow Demand	0.13	0.00	0.13	-0.10	-0.77	-0.92	-0.60	-0.74
Rapid Supply/Slow Demand (15)	0.08	-0.05	0.13	-0.09	-0.78	-0.92	-0.61	-0.76
Standalone *AEO97* High Technology Cases	-0.88	-0.89	-0.44	-0.68	-1.35	-1.46	NA	NA

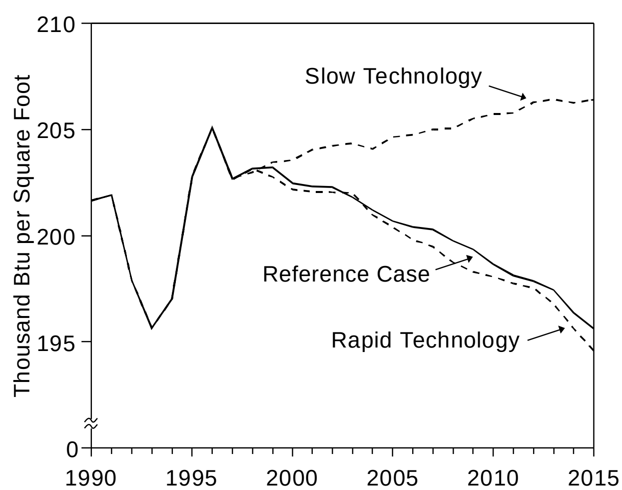
Btu = British thermal unit.
NA = not applicable.
Reference case = adjusted *AEO97* reference case.
Sources: Energy Information Administration, *Annual Energy Outlook 1997,* DOE/EIA-0383(96) (Washington, DC, December 1996), Tables A4, A5, A6, and A20 and Tables F1, F2, F3, F4, F7, F8, and F10 (standalone high technology cases); and AEO97 National Energy Modeling System runs POLBASE.D032497A, ISS97HH.D032597A, ISS97LL.D032597A, ISS97LH.D032597A, ISS97LN.D032697A, ISS97L3.D032897A, ISS97HN.D032597A, ISS97H3.D032897A, ISS97BO.D032697A, ISS97B2.D032797A, ISS97HL.D032597A, and ISS97H1.D032897A.

Figure 3. U.S. Residential Energy Intensity, 1990-2015: Comparison of Three Cases



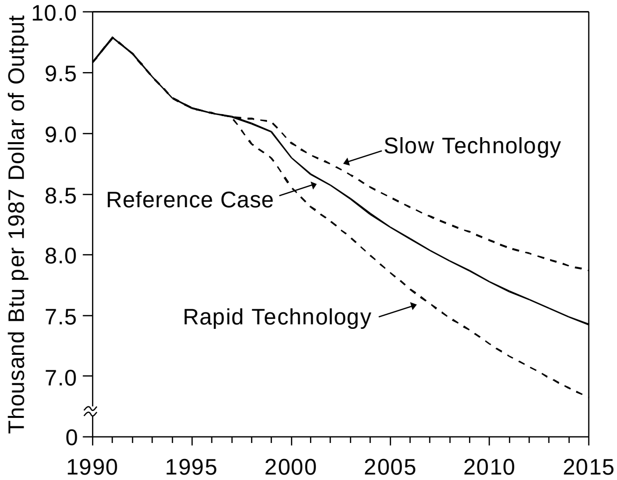
Source: Energy Information Administration, AEO97 National Energy Modeling System runs POLBASE.D032497A (reference case), ISS97HH.D032597A (rapid technology), and ISS97LL. D032597A (slow technology).

Figure 4. U.S. Commercial Energy Intensity, 1990-2015: Comparison of Three Cases



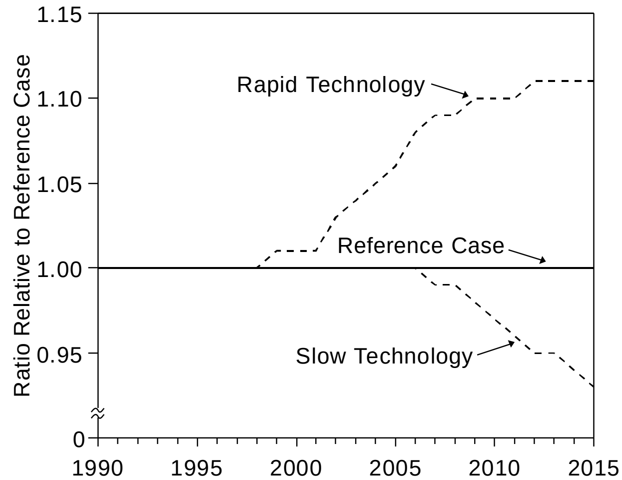
Source: Energy Information Administration, AEO97 National Energy Modeling System runs POLBASE.D032497A (reference case), ISS97HH.D032597A (rapid technology), and ISS97LL. D032597A (slow technology).

Figure 5. U.S. Industrial Energy Intensity, 1990-2015: Comparison of Three Cases



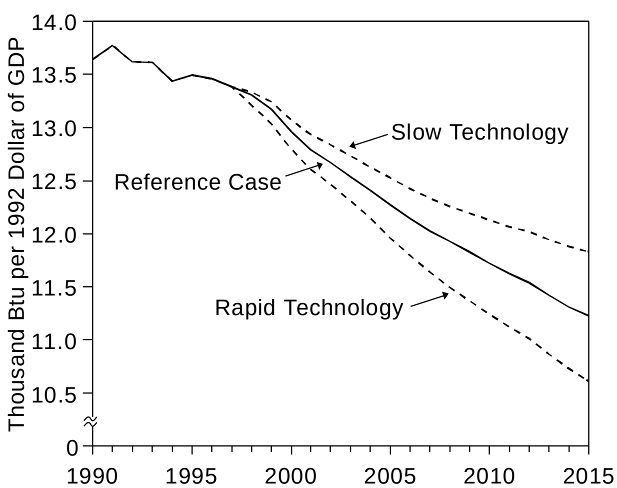
Source: Energy Information Administration, AEO97 National Energy Modeling System runs POLBASE.D032497A (reference case), ISS97HH.D032597A (rapid technology), and ISS97LL. D032597A (slow technology).

Figure 6. Variation from Reference Case New Car Fuel Efficiency (Mile per Gallon) in Two Alternative Cases, 1990-2015



Source: Energy Information Administration, AEO97 National Energy Modeling System runs POLBASE.D032497A (reference case), ISS97HH.D032597A (rapid technology), and ISS97LL. D032597A (slow technology).

Figure 7. U.S. Primary Energy Intensity, 1990-2015: Comparison of Three Cases



Source: Energy Information Administration, AEO97 National Energy Modeling System runs POLBASE.D032497A (reference case), ISS97HH.D032597A (rapid technology), and ISS97LL. D032597A (slow technology).

demand case, as illustrated in Figures 3 through 7. Residential energy intensity is defined as the annual energy used per household. For the commercial sector, energy intensity is measured by the amount of energy used per square foot. For the industrial sector, energy intensity is measured as energy used per unit output. Nationally, energy intensity is measured as total energy use divided by GDP. For transportation, the ratio of miles per gallon (mpg) for automobiles in the specific case divided by mpg in the reference case is taken as a measure of efficiency change.

The introduction of advanced technologies at reduced costs can have a significant impact on the rate at which energy intensity declines. Relative to the slow supply/slow demand technology case, use of the reference case menu of technologies increased the rate of overall primary energy intensity improvement by 42 percent (from -0.65 to -0.92) and delivered energy intensity improvement by 23 percent (from -0.66 to -0.81). The rapid technology assumptions increased the rate of primary intensity improvement by 83 percent and delivered energy intensity improvement by 65 percent relative to the slow supply/slow demand case.

The Importance of Consumer Hurdle Rates

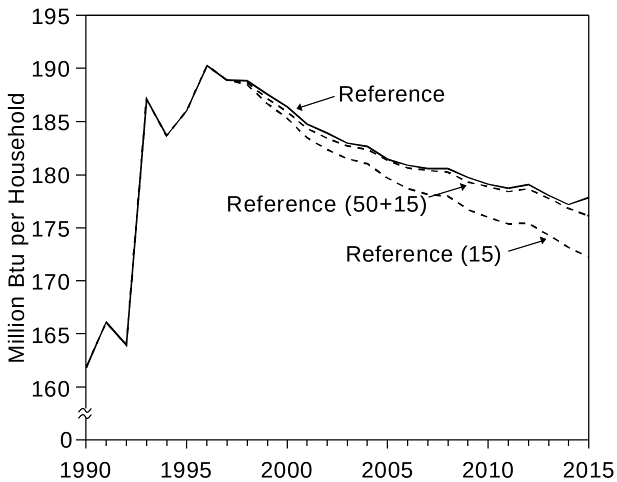
To examine the importance of altering consumer hurdle rates and their influence on the rate of energy intensity change, groupings with the same technology characterizations but different residential and commercial hurdle rates were examined—e.g., the reference cases[9] with three different hurdle rates (Figures 8 and 9) and the

[9]The hurdle rate for residential space heating, the single biggest end use in residential markets, was already at 15 percent in the reference case.

rapid supply and rapid demand cases with three different hurdle rates (Figures 10 and 11).

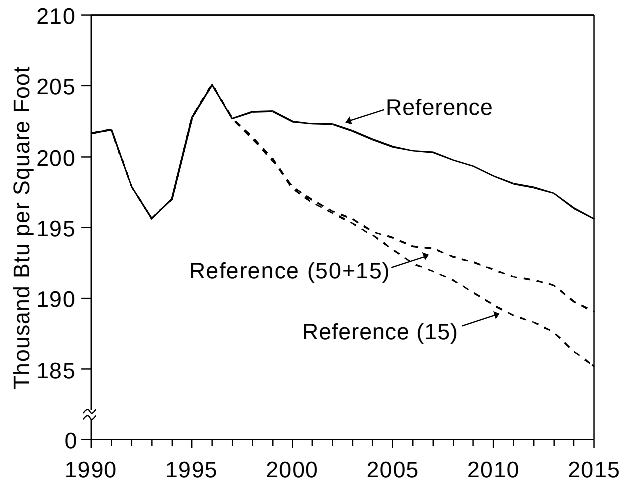
All else being equal, altering consumer behavior appears to be a more powerful force in reducing energy intensity in the residential and commercial energy markets than making advanced technologies at reduced costs available to the markets. The availability of advanced technologies with reduced costs relative to the reference case, as in the rapid technology case, can accelerate the rate of residential primary energy intensity improvement by 45 percent without assuming changes

Figure 8. U.S. Residential Energy Intensity, 1990-2015: Comparison of Three Cases



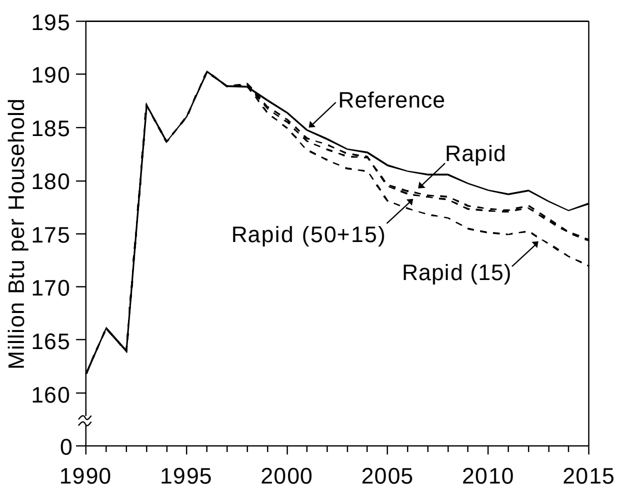
Source: Energy Information Administration, AEO97 National Energy Modeling System runs POLBASE.D032497A (reference case), ISS97BO.D032697A (reference (50+15)), and ISS97B2.D032797A (reference (15)).

Figure 9. U.S. Commercial Energy Intensity, 1990-2015: Comparison of Three Cases



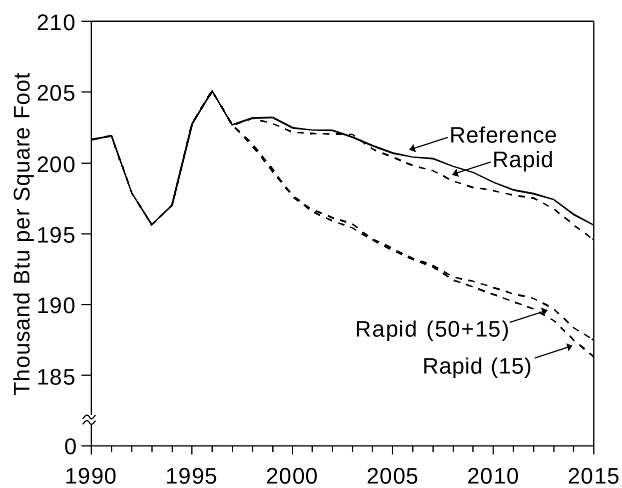
Source: Energy Information Administration, AEO97 National Energy Modeling System runs POLBASE.D032497A (reference case), ISS97BO.D032697A (reference (50+15)), and ISS97B2.D032797A (reference (15)).

Figure 10. U.S. Residential Energy Intensity, 1990-2015: Comparison of Four Cases



Source: Energy Information Administration, AEO97 National Energy Modeling System runs POLBASE.D032497A (reference case), ISS97HH.D032597A (rapid supply/rapid demand), ISS97HN.D032597A (rapid supply/rapid demand (50+15)), and ISS97H3.D032897A (rapid supply/rapid demand (15)).

Figure 11. U.S. Commercial Energy Intensity, 1990-2015: Comparison of Four Cases



Source: Energy Information Administration, AEO97 National Energy Modeling System runs POLBASE.D032497A (reference case), ISS97HH.D032597A (rapid supply/rapid demand), ISS97HN.D032597A (rapid supply/rapid demand (50+15)), and ISS97H3.D032897A (rapid supply/rapid demand (15)).

to consumer behavior. When both advanced supply and demand technologies with reduced costs were made available and hurdle rates were reduced to 15 percent, the residential primary energy intensity decline rate increased by 77 percent relative to the reference case. However, as the discussion below illustrates, the impacts of making advanced technologies with reduced costs available and reducing hurdle rates are not additive.

Relative to the reference case with reference hurdle rates, residential sector primary energy intensity declined 23 percent faster (-0.27) in the 50 percent hurdle rate reduction case (reference (50+15)) and 73 percent faster (-0.38) in the 15 percent hurdle rate reduction case (reference (15)), in which the nonfinancial hurdle rate was reduced to zero. When advanced technologies with reduced costs were available for both supply and demand (in the rapid technology cases), changes in consumer choices were still important, but less so than when the reference case technological progress assumptions were used. For example, in the rapid technology case with 15 percent hurdle rates (rapid supply / rapid demand (15)), the change in residential primary energy intensity (-0.39) improved by only 22 percent relative to the rate of change (-0.32) in the rapid technology case with reference case hurdle rates (rapid supply / rapid demand (50+15)).

In the commercial sector, relative to the reference case with reference hurdle rates, primary energy intensity declined 94 percent faster in the 50 percent hurdle rate reduction case (-0.35) and 150 percent faster (-0.45) in the 15 percent hurdle rate reduction case, in which the nonfinancial hurdle rate was reduced to zero. When advanced technologies at reduced costs were available for both supply and demand (in the rapid technology cases), changes in consumer choices were less important. For example, in the rapid technology case with 15 percent hurdle rates, commercial primary energy intensity (-0.42) improved by 100 percent relative to the rapid technology case with reference case hurdle rates (-0.21).

The residential and commercial sectors showed different strengths of response to changes in hurdle rates and changes in the availability of lower cost advanced technologies because of differences in the assumed behavior of the two markets. The hurdle rates, imputed from historical equipment sales, have different values for the sectors. In the commercial sector, equipment purchase decisions are more likely to be based on levelized costs than they are in the residential market, where initial equipment costs are weighed far more heavily than operating costs over the life of the equipment. Consequently, changes in hurdle rates in the commercial energy market are likely to have a significantly greater impact on equipment decisions than they are in the residential energy market.

In the slow supply / rapid demand (15) technology case, as compared with the rapid supply / rapid demand case, higher prices in the slow supply technology case stimulate consumers to adopt appliances with greater efficiency. Absent carbon mitigation policies or new appliance standards, advances on the supply side tend to reduce fuel prices and reduce the incentives for buying higher efficiency end-use equipment. The availability of advanced, low-cost, demand-side technologies reduces energy consumption and consequently reduces energy prices.

Limits to Annual Energy Intensity Decline Rates in Energy Markets

The limits to energy intensity decline rates in the residential and commercial energy markets have often been points of contention, since the two sectors represent a little more than one-third of the energy consumed in the United States when electricity losses are included. The other two-thirds are roughly evenly divided between the industrial and transportation sectors. To explore the limits of energy intensity decline rates in the U.S. energy system, the standalone runs of the *AEO97* high technology cases were examined.

In the extreme, the limits to energy intensity decline rates in the residential and commercial markets can be determined by assuming that the best available technologies are selected, irrespective of energy or equipment costs, as indicated in the *AEO97 standalone runs*. In such a case, the residential delivered and primary energy intensity decline rates are -0.88 and -0.89 percent per year respectively between 1995 and 2015 (Table 2). For the commercial energy market, the delivered and primary energy intensity decline rates are -0.44 and -0.68 percent per year respectively between 1995 and 2015. Unless consumer patterns change dramatically with respect to equipment retirements in the residential and commercial energy markets, the annual rates of energy intensity decline are limited to these rates.

From 1960 to 1994, the 10-year moving average of the aggregate industrial intensity decline rate was 1.2 percent per year, with a standard deviation of 1.1 percent. Thus, a change of one standard deviation would approximately double the intensity decline. The high supply / high demand technology case was designed to emulate this result by approximately doubling the projected energy intensity decline rates for the energy-intensive industries. Changes in aggregate energy intensity result both from changing equipment and production efficiency and from changing composition of industrial output. Since the composition of industrial output was assumed to remain the same as in the reference case, aggregate intensity fell by only 1.4 percent annually.

Finally, transportation sector efficiency improvements relative to the reference case are limited by the growing proportion of sport/utility vehicles. In the rapid supply/rapid demand technology case, new light trucks and sport/utility vehicles experience a 17-percent improvement in mpg because of their weight and horsepower characteristics relative to the reference case. Automobiles experience an mpg efficiency improvement of about 10 percent relative to the reference case. Because of the slow vehicle turnover rate, the average fleet mpg in the rapid supply/rapid demand case is only 8 percent higher than in the reference case in 2015.

Under the assumptions of this study, when prices matter for consumer decisionmaking and the analysis is performed in an integrated framework, the effective limit to the annual primary energy intensity decline rate is about -1.25 percent, even when rapid supply and rapid demand technologies are assumed.

Impacts of Technological Breakthroughs Across the Energy System

This study establishes the critical role that consumer preferences (hurdle rates) play in the success of any energy use reduction or carbon mitigation or abatement strategy. Technological advances and rates of penetration on one side of the demand-supply equation reduce the potential for additional energy savings from the other side. That is, as advanced demand technologies succeed in displacing less efficient end-use technologies, the demand for each fuel form—electricity, natural gas, distillate fuel, and coal—tends to decline, diminishing the adoption of potentially successful supply technologies. For example, as electricity end-use technologies improve, the demand for electricity will decline; consequently, the market for new, more efficient supply technologies will be diminished. Alternatively, if supply technologies succeed, then the cost of supplying the fuel will be lower, and the value of paying additional capital to buy higher efficiency end-use equipment will also be diminished.

Observations and Conclusions

In this analysis, as in the pilot study, we began with relatively simple assumptions about what constitutes slow and rapid technological progress for energy supply and demand. The assumptions used for the *AEO97* technology cases for each sector were used as the starting point for these integrated cases. Sensitivity analysis was performed on residential and commercial sector hurdle rates.

One of the major benefits of this study was to define technology cases in a way that can provide greater value to our clients. Some of the major insights of this and the previous study include:

- A key determinant of energy consumption in end-use markets is the penetration of advanced technologies, which is determined by two factors: growth in demand and the rate of replacement of existing equipment. Given the range of fuel prices represented by these cases, premature retirement of residential and commercial sector equipment was determined to be uneconomic.

- Under the assumptions of this study, it appears that programs that increase the willingness of consumers to purchase highly efficient *existing* equipment are important in reducing energy intensity.

- Under the variety of technology assumptions of this study, including the assumption that nonfinancial hurdle rates in the residential and commercial energy markets are reduced to zero, and assuming current laws, policies, programs, and equipment retirement patterns, the annual rate of decline of the ratio of primary energy to GDP appears to be bounded by -1.25 percent.

- Successful R&D in the oil and gas production and exploration industries will, all else being equal, reduce the cost of domestic crude oil and gas supply, increase the profitability of both domestic industries, increase oil and gas production, and reduce oil and gas prices in U.S. energy markets.

- In the cases considered, U.S. dependence on oil imports is minimized when rapid technology advances for both supply and demand are developed, commercialized, and adopted in the U.S. energy system. Also, technology improvements in either the supply or demand sector reduce oil imports.

- The rate of progress in demand technologies primarily affects consumption of fuels, with secondary impacts on fuel prices. The rate of supply technological progress primarily affects fuel prices and domestic production, with some important secondary impacts on consumption. Consequently, fuel consumption and carbon emissions are likely to be at their greatest when demand technological progress is slower.

- Carbon emissions are at their lowest when demand technological progress is most rapid and resource prices are high.

- Rapid deployment of higher efficiency equipment for demand tends to postpone the need for new generating technologies, reducing the market potential for advanced generation technologies.

- Although none of the cases examined achieved carbon stabilization, despite the favorable assumptions made in the rapid technology cases, the results suggest that R&D investments that succeed in developing low-cost, high-efficiency end-use technologies and facilitating market acceptance of them could play a significant role in moderating carbon emissions in the United States. Successful R&D programs that improve the availability and market acceptance of cost-efficient transportation technologies, coupled with successful oil and gas supply R&D programs, could have a significant impact on reducing dependence on imported oil.

- In the context of the assumptions of this study, technological progress for demand technologies has a greater potential impact in reducing oil imports and carbon emissions than does progress for the supply technologies. However, numerous uncertainties cloud our ability to see with clarity the evolution of the U.S. energy system. The principal uncertainties relate to the menu of advanced technologies that might be commercially available in the future, their cost and performance characteristics, the rate at which new high-efficiency technologies may be developed through public and private R&D efforts, and how consumer choices will and can evolve over time. An empirical issue is the relationship between R&D funding, technical success, and market acceptance. These research issues remain unanswered scientific challenges. Public awareness and acceptance of superior technologies are likely to be key elements of the way choices are made in the future.

Limitations of the Study

Two major limitations of this study were that it did not attempt to evaluate the energy programs of the Federal Government or their programmatic goals, and that technology changes and market effects were isolated to U.S. markets. Further, future geopolitical events (e.g., greater instability in international energy markets, or environmental initiatives such as binding commitments to reduce carbon emissions) could cause an increased focus on end-use and supply improvement and implementation than represented in this study.

A third limitation is that the economic impacts of investments in energy-saving technologies were not fully considered in this analysis—that is, although the energy price impacts of using advanced technologies were incorporated in the analysis, the energy investment impacts of the new technologies on the U.S. economy with respect to manufacturing investments and other infrastructure investments were not considered.[10]

[10]There is a multi-year effort underway to design and possibly implement the capital investment feedback from the energy sector to the NEMS macroeconomic module.

Appendix
Comparison of the *AEO97* Reference Case, Slow Supply/Slow Demand, and Rapid Supply/Rapid Demand Technology Cases

Table A1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Production										
Crude Oil and Lease Condensate	13.89	10.87	11.58	12.46	10.07	11.42	12.89	9.58	11.15	13.10
Natural Gas Plant Liquids	2.37	2.92	2.95	2.87	2.94	2.99	2.93	3.19	3.44	3.45
Dry Natural Gas	19.01	22.55	22.85	22.25	24.10	24.64	24.26	24.70	26.66	26.87
Coal	22.06	25.71	24.05	23.45	28.01	25.10	23.79	32.14	26.57	24.33
Nuclear Power	7.19	6.98	6.98	6.98	6.55	6.55	6.55	4.79	4.79	4.79
Renewable Energy[1]	6.29	6.93	6.93	6.86	7.41	7.29	7.14	7.85	7.90	7.47
Other[2]	1.34	0.42	0.41	0.42	0.45	0.40	0.42	0.45	0.42	0.46
Total	**72.16**	**76.39**	**75.76**	**75.29**	**79.52**	**78.40**	**78.00**	**82.70**	**80.93**	**80.47**
Imports										
Crude Oil [3]	15.69	21.42	20.69	19.69	22.83	21.49	19.91	23.77	22.15	20.04
Petroleum Products[4]	3.19	7.20	6.73	5.96	8.89	7.99	5.98	10.52	8.38	5.42
Natural Gas	2.90	4.04	4.04	3.92	4.17	4.28	4.14	4.26	4.50	4.26
Other Imports[5]	0.60	0.73	0.70	0.65	0.73	0.68	0.65	0.71	0.66	0.63
Total	**22.38**	**33.39**	**32.16**	**30.22**	**36.62**	**34.43**	**30.68**	**39.26**	**35.69**	**30.35**
Exports										
Petroleum[6]	2.02	1.74	1.78	1.77	1.86	1.90	1.83	1.98	1.95	1.84
Natural Gas	0.16	0.21	0.21	0.21	0.22	0.22	0.22	0.22	0.22	0.22
Coal	2.26	2.59	2.59	2.60	2.81	2.82	2.86	2.96	3.04	3.04
Total	**4.45**	**4.54**	**4.58**	**4.59**	**4.89**	**4.94**	**4.91**	**5.16**	**5.21**	**5.10**
Discrepancy[7]	**0.83**	**-0.33**	**-0.33**	**-0.28**	**-0.24**	**-0.25**	**-0.16**	**-0.48**	**-0.47**	**-0.38**
Consumption										
Petroleum Products[8]	34.92	40.88	40.39	39.47	43.21	42.25	40.25	45.18	43.25	40.34
Natural Gas	22.18	26.23	26.54	25.83	27.85	28.55	28.03	28.52	30.76	30.74
Coal	19.95	23.44	21.75	21.14	25.54	22.58	21.25	29.53	23.86	21.63
Nuclear Power	7.19	6.98	6.98	6.98	6.55	6.55	6.55	4.79	4.79	4.79
Renewable Energy[1]	6.30	6.93	6.93	6.87	7.42	7.30	7.16	7.87	7.91	7.48
Other[9]	0.39	0.43	0.41	0.37	0.44	0.40	0.37	0.43	0.39	0.35
Total	**90.93**	**104.90**	**103.01**	**100.65**	**111.02**	**107.63**	**103.60**	**116.32**	**110.94**	**105.33**
Net Imports - Petroleum	**16.87**	**26.88**	**25.65**	**23.88**	**29.86**	**27.57**	**24.06**	**32.31**	**28.59**	**23.62**
Prices (1995 dollars per unit)										
World Oil Price (dollars per barrel)[10]	17.26	20.72	19.74	18.62	22.03	20.53	18.27	23.26	21.13	18.24
Gas Wellhead Price (dollars per Mcf)[11]	1.61	2.13	1.86	1.58	2.51	1.95	1.41	2.87	2.09	1.31
Coal Minemouth Price (dollars per ton)	18.90	20.09	17.76	15.76	20.01	16.93	14.12	20.28	15.57	12.12

[1]Includes utility and nonutility grid-connected electricity from hydroelectric, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes nonmarketed renewable energy. See Table B18 for selected nonmarketed residential and commercial renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Mcf = Thousand cubic feet.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1995 may differ from published data due to internal conversion factors.
Sources: 1995 natural gas price: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(96/6) (Washington, DC, June 1996). 1995 natural gas supply derived from: EIA, *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC November 1996). 1995 coal minemouth price, coal production, and exports derived from: EIA, *Monthly Energy Review*, DOE/EIA-0035(96/08) (Washington, DC, August 1996). Other 1995 values: EIA, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). **Projections:** EIA, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology).

Table A2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Energy Consumption										
Residential										
Distillate Fuel	0.85	0.81	0.79	0.77	0.80	0.75	0.74	0.79	0.73	0.71
Kerosene	0.07	0.07	0.07	0.07	0.07	0.07	0.06	0.07	0.06	0.06
Liquefied Petroleum Gas	0.40	0.45	0.44	0.43	0.47	0.45	0.44	0.49	0.45	0.44
Petroleum Subtotal	1.32	1.34	1.30	1.27	1.34	1.27	1.24	1.35	1.24	1.22
Natural Gas	5.01	5.54	5.43	5.47	5.77	5.57	5.65	6.04	5.87	5.81
Coal	0.05	0.05	0.05	0.04	0.05	0.04	0.04	0.04	0.04	0.04
Renewable Energy[1]	0.57	0.57	0.56	0.54	0.57	0.55	0.52	0.58	0.54	0.51
Electricity	3.56	4.20	4.14	4.07	4.56	4.45	4.37	5.02	4.84	4.76
Delivered Energy	**10.51**	**11.69**	**11.47**	**11.40**	**12.29**	**11.88**	**11.83**	**13.03**	**12.53**	**12.33**
Electricity Related Losses	7.92	8.91	8.58	8.44	9.62	8.98	8.82	10.39	9.28	9.06
Total	**18.43**	**20.60**	**20.05**	**19.84**	**21.90**	**20.86**	**20.65**	**23.41**	**21.81**	**21.40**
Commercial										
Distillate Fuel	0.41	0.36	0.36	0.36	0.35	0.35	0.35	0.34	0.34	0.34
Residual Fuel	0.17	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.14
Kerosene	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Liquefied Petroleum Gas	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Motor Gasoline[2]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02
Petroleum Subtotal	0.67	0.60	0.60	0.60	0.59	0.59	0.59	0.59	0.59	0.59
Natural Gas	3.16	3.45	3.45	3.46	3.54	3.54	3.58	3.66	3.66	3.71
Coal	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.09	0.09
Renewable Energy[3]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	3.23	3.75	3.72	3.71	3.98	3.92	3.89	4.24	4.16	4.13
Delivered Energy	**7.15**	**7.89**	**7.85**	**7.86**	**8.21**	**8.14**	**8.15**	**8.59**	**8.50**	**8.52**
Electricity Related Losses	7.18	7.97	7.71	7.68	8.39	7.90	7.85	8.78	7.97	7.87
Total	**14.33**	**15.86**	**15.56**	**15.54**	**16.60**	**16.04**	**16.00**	**17.38**	**16.47**	**16.40**
Industrial[4]										
Distillate Fuel	1.15	1.38	1.39	1.35	1.48	1.48	1.41	1.55	1.55	1.46
Liquefied Petroleum Gas	2.01	2.27	2.21	2.11	2.38	2.30	2.15	2.47	2.36	2.19
Petrochemical Feedstocks	1.16	1.34	1.30	1.23	1.41	1.35	1.26	1.47	1.40	1.28
Residual Fuel	0.34	0.33	0.31	0.28	0.36	0.31	0.25	0.39	0.32	0.25
Motor Gasoline[2]	0.20	0.24	0.24	0.23	0.26	0.26	0.24	0.27	0.27	0.25
Other Petroleum[5]	3.83	4.51	4.37	4.26	4.71	4.51	4.26	4.92	4.52	4.22
Petroleum Subtotal	8.68	10.08	9.82	9.45	10.60	10.21	9.58	11.07	10.43	9.65
Natural Gas[6]	9.74	11.14	11.05	10.65	11.51	11.47	11.12	11.59	11.73	11.41
Metallurgical Coal	0.88	0.69	0.69	0.69	0.62	0.62	0.62	0.55	0.55	0.55
Steam Coal	1.59	1.84	1.74	1.56	2.03	1.86	1.52	2.25	2.06	1.55
Net Coal Coke Imports	0.03	0.11	0.10	0.10	0.14	0.12	0.12	0.16	0.14	0.14
Coal Subtotal	2.51	2.64	2.53	2.35	2.79	2.60	2.26	2.95	2.75	2.24
Renewable Energy[7]	1.74	2.13	2.12	2.11	2.29	2.29	2.26	2.43	2.42	2.37
Electricity	3.46	4.19	4.08	3.86	4.50	4.32	3.96	4.80	4.56	4.09
Delivered Energy	**26.12**	**30.17**	**29.60**	**28.42**	**31.68**	**30.89**	**29.18**	**32.84**	**31.88**	**29.77**
Electricity Related Losses	7.69	8.91	8.46	8.00	9.48	8.71	7.98	9.94	8.74	7.79
Total	**33.81**	**39.08**	**38.06**	**36.42**	**41.16**	**39.60**	**37.16**	**42.78**	**40.62**	**37.56**

Table A2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Transportation										
Distillate Fuel	4.42	5.49	5.44	5.19	5.87	5.76	5.29	6.14	5.98	5.32
Jet Fuel [8]	3.13	4.14	4.11	4.12	4.59	4.50	4.49	4.94	4.78	4.72
Motor Gasoline[2]	14.65	16.63	16.67	16.42	17.26	17.20	16.40	17.68	17.24	15.96
Residual Fuel	1.08	1.47	1.47	1.47	1.64	1.64	1.65	1.77	1.78	1.79
Liquefied Petroleum Gas	0.03	0.11	0.11	0.11	0.17	0.17	0.16	0.21	0.21	0.19
Other Petroleum[9]	0.26	0.31	0.31	0.31	0.33	0.33	0.33	0.34	0.34	0.34
Petroleum Subtotal	23.56	28.15	28.12	27.63	29.86	29.61	28.32	31.08	30.32	28.33
Pipeline Fuel Natural Gas	0.72	0.82	0.84	0.84	0.86	0.88	0.91	0.88	0.93	0.97
Compressed Natural Gas	0.01	0.18	0.18	0.18	0.26	0.26	0.24	0.31	0.30	0.27
Renewable Energy (E85)[10]	0.00	0.02	0.02	0.02	0.06	0.06	0.06	0.09	0.09	0.08
Methanol [11]	0.00	0.02	0.02	0.02	0.06	0.06	0.06	0.09	0.08	0.08
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.05	0.05	0.05	0.08	0.08	0.07	0.10	0.10	0.09
Delivered Energy	**24.31**	**29.25**	**29.24**	**28.74**	**31.18**	**30.96**	**29.65**	**32.54**	**31.83**	**29.82**
Electricity Related Losses	0.05	0.11	0.11	0.11	0.17	0.17	0.15	0.21	0.20	0.16
Total	**24.36**	**29.36**	**29.34**	**28.85**	**31.35**	**31.12**	**29.80**	**32.76**	**32.03**	**29.98**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	6.82	8.05	7.97	7.67	8.49	8.34	7.79	8.82	8.60	7.83
Kerosene	0.11	0.11	0.11	0.11	0.11	0.11	0.10	0.11	0.11	0.10
Jet Fuel [8]	3.13	4.14	4.11	4.12	4.59	4.50	4.49	4.94	4.78	4.72
Liquefied Petroleum Gas	2.49	2.90	2.82	2.71	3.09	2.98	2.81	3.23	3.09	2.88
Motor Gasoline[2]	14.87	16.89	16.94	16.68	17.54	17.48	16.67	17.97	17.53	16.24
Petrochemical Feedstocks	1.16	1.34	1.30	1.23	1.41	1.35	1.26	1.47	1.40	1.28
Residual Fuel	1.58	1.93	1.92	1.88	2.13	2.10	2.04	2.30	2.24	2.18
Other Petroleum[12]	4.07	4.80	4.66	4.55	5.02	4.82	4.58	5.23	4.84	4.54
Petroleum Subtotal	34.24	40.16	39.83	38.95	42.38	41.68	39.74	44.08	42.59	39.79
Natural Gas[6]	18.64	21.13	20.95	20.60	21.94	21.73	21.49	22.48	22.48	22.18
Metallurgical Coal	0.88	0.69	0.69	0.69	0.62	0.62	0.62	0.55	0.55	0.55
Steam Coal	1.73	1.97	1.87	1.68	2.17	2.00	1.65	2.38	2.19	1.68
Net Coal Coke Imports	0.03	0.11	0.10	0.10	0.14	0.12	0.12	0.16	0.14	0.14
Coal Subtotal	2.64	2.77	2.66	2.48	2.92	2.73	2.39	3.09	2.88	2.37
Renewable Energy[13]	2.31	2.72	2.70	2.67	2.93	2.90	2.84	3.10	3.05	2.97
Methanol [11]	0.00	0.02	0.02	0.02	0.06	0.06	0.06	0.09	0.08	0.08
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	10.27	12.19	11.99	11.69	13.13	12.77	12.29	14.17	13.67	13.06
Delivered Energy	**68.10**	**79.00**	**78.16**	**76.42**	**83.36**	**81.87**	**78.81**	**87.00**	**84.75**	**80.44**
Electricity Related Losses	22.83	25.91	24.85	24.23	27.66	25.76	24.79	29.32	26.20	24.89
Total	**90.93**	**104.90**	**103.01**	**100.65**	**111.02**	**107.63**	**103.60**	**116.32**	**110.94**	**105.33**
Electric Generators[14]										
Distillate Fuel	0.08	0.12	0.12	0.10	0.15	0.14	0.14	0.18	0.17	0.18
Residual Fuel	0.60	0.60	0.44	0.41	0.68	0.43	0.38	0.92	0.49	0.37
Petroleum Subtotal	0.68	0.72	0.56	0.51	0.83	0.57	0.51	1.10	0.66	0.55
Natural Gas	3.54	5.10	5.60	5.23	5.91	6.82	6.54	6.04	8.27	8.56
Steam Coal	17.31	20.67	19.08	18.66	22.62	19.85	18.86	26.45	20.98	19.26
Nuclear Power	7.19	6.98	6.98	6.98	6.55	6.55	6.55	4.79	4.79	4.79
Renewable Energy[15]	3.99	4.22	4.23	4.19	4.49	4.40	4.31	4.77	4.86	4.52
Electricity Imports	0.39	0.41	0.39	0.34	0.38	0.34	0.31	0.34	0.30	0.28
Total	**33.10**	**38.10**	**36.84**	**35.92**	**40.78**	**38.53**	**37.09**	**43.49**	**39.86**	**37.95**

Table A2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1995	Projections 2005 Slow Technology	2005 Reference	2005 Rapid Technology	2010 Slow Technology	2010 Reference	2010 Rapid Technology	2015 Slow Technology	2015 Reference	2015 Rapid Technology
Total Energy Consumption										
Distillate Fuel	6.90	8.17	8.09	7.77	8.64	8.48	7.93	9.00	8.77	8.02
Kerosene	0.11	0.11	0.11	0.11	0.11	0.11	0.10	0.11	0.11	0.10
Jet Fuel [8]	3.13	4.14	4.11	4.12	4.59	4.50	4.49	4.94	4.78	4.72
Liquefied Petroleum Gas	2.49	2.90	2.82	2.71	3.09	2.98	2.81	3.23	3.09	2.88
Motor Gasoline[2]	14.87	16.89	16.94	16.68	17.54	17.48	16.67	17.97	17.53	16.24
Petrochemical Feedstocks	1.16	1.34	1.30	1.23	1.41	1.35	1.26	1.47	1.40	1.28
Residual Fuel	2.18	2.53	2.36	2.29	2.81	2.52	2.42	3.22	2.74	2.55
Other Petroleum[12]	4.07	4.80	4.66	4.55	5.02	4.82	4.58	5.23	4.84	4.54
Petroleum Subtotal	34.92	40.88	40.39	39.47	43.21	42.25	40.25	45.18	43.25	40.34
Natural Gas	22.18	26.23	26.54	25.83	27.85	28.55	28.03	28.52	30.76	30.74
Metallurgical Coal	0.88	0.69	0.69	0.69	0.62	0.62	0.62	0.55	0.55	0.55
Steam Coal	19.04	22.64	20.95	20.34	24.79	21.84	20.51	28.83	23.17	20.94
Net Coal Coke Imports	0.03	0.11	0.10	0.10	0.14	0.12	0.12	0.16	0.14	0.14
Coal Subtotal	19.95	23.44	21.75	21.14	25.54	22.58	21.25	29.53	23.86	21.63
Nuclear Power	7.19	6.98	6.98	6.98	6.55	6.55	6.55	4.79	4.79	4.79
Renewable Energy[16]	6.30	6.93	6.93	6.87	7.42	7.30	7.16	7.87	7.91	7.48
Methanol [11]	0.00	0.02	0.02	0.02	0.06	0.06	0.06	0.09	0.08	0.08
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.39	0.41	0.39	0.34	0.38	0.34	0.31	0.34	0.30	0.28
Total	**90.93**	**104.90**	**103.01**	**100.65**	**111.02**	**107.63**	**103.60**	**116.32**	**110.94**	**105.33**
Energy Use and Related Statistics										
Delivered Energy Use	68.10	79.00	78.16	76.42	83.36	81.87	78.81	87.00	84.75	80.44
Total Energy Use	90.93	104.89	103.00	100.64	110.99	107.60	103.58	116.29	110.91	105.30
Population (millions)	263.58	287.12	287.12	287.12	298.92	298.92	298.92	311.19	311.19	311.19
Gross Domestic Product (billion 1992 dollars)	6738.95	8371.88	8390.20	8414.71	9149.54	9182.30	9215.74	9833.48	9880.75	9924.74
Total Carbon Emissions (million metric tons)	1423.60	1676.29	1632.25	1591.96	1794.01	1716.16	1641.02	1940.67	1797.86	1689.89

[1]Includes wood used for residential heating. See Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps and solar thermal hot water heating.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector electricity cogenerated by using wood and wood waste, municipal solid waste, and other biomass. See Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating.
[4]Fuel consumption includes consumption for cogeneration.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Includes lease and plant fuel.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
[8]Includes naphtha and kerosene type.
[9]Includes aviation gas and lubricants.
[10]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[11]Only M85 (85 percent methanol).
[12]Includes unfinished oils, natural gasoline, motor gasoline blending compounds, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to electric utilities and for self use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps and solar thermal hot water heaters.
[14]Includes consumption of energy by all electric power generators for grid-connected power except cogenerators, which produce electricity as a by-product of other processes.
[15]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, E85, wind, photovoltaic and solar thermal sources.
[16]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes nonmarketed renewable energy consumption for geothermal heat pumps and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1995 may differ from published data due to internal conversion factors. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 1995 natural gas lease, plant, and pipeline fuel values: Energy Information Administration (EIA), *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). 1995 transportation sector compressed natural gas consumption: EIA, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology).1995 electric utility fuel consumption: EIA, *Electric Power Annual, Volume I*, DOE/EIA-0348(95)/1 (Washington, DC, July 1996). 1995 nonutility consumption estimates: EIA Form 867, "Annual Nonutility Power Producer Report." Other 1995 values: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). **Projections:** EIA, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology).

Table A3. Energy Prices by Sector and Source
(1995 Dollars per Million Btu)

Sector and Source	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Residential	**12.87**	**13.15**	**12.72**	**12.22**	**13.48**	**12.70**	**11.80**	**13.74**	**12.53**	**11.47**
Primary Energy	6.28	6.29	6.02	5.68	6.40	5.90	5.25	6.50	5.76	4.96
Petroleum Products	7.51	9.02	8.72	8.49	9.42	9.01	8.45	9.59	8.97	8.22
Distillate Fuel	6.24	7.52	7.26	7.04	7.76	7.40	6.94	7.82	7.36	6.69
Liquefied Petroleum Gas	10.29	11.73	11.35	11.09	12.27	11.77	11.04	12.50	11.58	10.70
Natural Gas	6.01	5.68	5.42	5.06	5.73	5.23	4.57	5.84	5.11	4.30
Electricity	24.68	24.46	23.68	23.13	24.59	23.21	22.19	24.46	22.51	21.15
Commercial	**13.22**	**13.03**	**12.67**	**12.22**	**13.32**	**12.64**	**11.82**	**13.42**	**12.40**	**11.32**
Primary Energy	4.82	4.90	4.62	4.29	5.06	4.55	3.94	5.24	4.52	3.72
Petroleum Products	4.58	5.60	5.33	5.11	5.86	5.49	5.01	5.97	5.45	4.79
Distillate Fuel	4.39	5.52	5.27	5.05	5.75	5.40	4.93	5.82	5.36	4.68
Residual Fuel	2.99	3.08	2.87	2.68	3.36	3.00	2.63	3.48	3.05	2.58
Natural Gas[1]	4.96	4.86	4.57	4.22	5.01	4.47	3.82	5.21	4.44	3.62
Electricity	23.41	21.99	21.60	21.09	22.07	21.35	20.45	21.79	20.63	19.39
Industrial [2]	**5.04**	**5.20**	**4.92**	**4.63**	**5.49**	**5.02**	**4.46**	**5.68**	**4.98**	**4.23**
Primary Energy	3.36	3.57	3.31	3.06	3.87	3.43	2.94	4.09	3.45	2.79
Petroleum Products	4.92	4.83	4.57	4.32	5.13	4.76	4.26	5.25	4.68	4.03
Distillate Fuel	4.61	5.45	5.20	4.98	5.69	5.35	4.89	5.81	5.33	4.65
Liquefied Petroleum Gas	6.53	6.34	5.89	5.52	6.68	6.13	5.39	6.78	5.89	4.99
Residual Fuel	2.55	3.13	2.92	2.72	3.46	3.04	2.63	3.70	3.04	2.53
Natural Gas[3]	2.28	2.76	2.46	2.16	3.13	2.56	1.99	3.48	2.71	1.90
Metallurgical Coal	1.76	1.81	1.74	1.60	1.81	1.59	1.46	1.82	1.48	1.33
Steam Coal	1.49	1.58	1.45	1.33	1.60	1.38	1.21	1.62	1.30	1.10
Electricity	14.68	13.88	13.58	13.18	13.85	13.31	12.65	13.57	12.72	11.83
Transportation	**7.92**	**8.82**	**8.58**	**8.27**	**8.96**	**8.60**	**7.85**	**8.96**	**8.31**	**7.38**
Primary Energy	7.92	8.81	8.57	8.26	8.94	8.58	7.84	8.94	8.29	7.36
Petroleum Products	7.92	8.82	8.58	8.27	8.94	8.58	7.84	8.93	8.28	7.35
Distillate Fuel [4]	8.03	8.93	8.70	8.49	8.99	8.66	8.11	8.95	8.42	7.61
Jet Fuel [5]	3.85	5.63	5.38	5.12	5.94	5.53	4.92	6.03	5.42	4.69
Motor Gasoline[6]	9.23	10.16	9.90	9.56	10.30	9.92	9.11	10.31	9.59	8.63
Residual Fuel	2.44	3.09	2.91	2.71	3.44	3.17	2.76	3.48	3.12	2.62
Natural Gas[7]	5.77	6.39	6.12	5.78	7.19	6.67	6.05	7.74	7.03	6.21
E85[8]	11.95	16.92	16.71	15.43	17.65	17.61	14.27	17.61	17.64	13.97
Electricity	15.26	14.60	14.51	14.51	14.51	14.35	14.26	14.17	13.82	13.75
Total End-Use Energy	**8.24**	**8.63**	**8.34**	**8.05**	**8.87**	**8.38**	**7.73**	**9.00**	**8.22**	**7.40**
Primary Energy	7.84	8.28	8.01	7.72	8.50	8.04	7.40	8.61	7.87	7.03
Electricity	20.89	20.02	19.56	19.16	20.08	19.23	18.52	19.89	18.60	17.63
Electric Generators[9]										
Fossil Fuel Average	1.48	1.66	1.54	1.38	1.75	1.57	1.32	1.79	1.60	1.27
Petroleum Products	2.78	3.46	3.35	3.14	3.78	3.62	3.23	3.85	3.59	3.20
Distillate Fuel	3.94	5.01	4.74	4.54	5.26	4.89	4.42	5.36	4.88	4.18
Residual Fuel	2.62	3.14	2.98	2.79	3.46	3.19	2.79	3.55	3.16	2.71
Natural Gas	2.01	2.62	2.36	2.03	2.99	2.48	1.89	3.36	2.66	1.87
Steam Coal	1.32	1.37	1.25	1.15	1.35	1.20	1.07	1.35	1.12	0.95

Table A3. Energy Prices by Sector and Source (Continued)
(1995 Dollars per Million Btu)

Sector and Source	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Average Price to All Users[10]										
Petroleum Products	7.07	7.77	7.56	7.29	7.95	7.63	6.98	7.95	7.39	6.56
Distillate Fuel [4]	6.98	7.99	7.75	7.53	8.12	7.77	7.22	8.12	7.60	6.79
Jet Fuel	3.85	5.63	5.38	5.12	5.94	5.53	4.92	6.03	5.42	4.69
Liquefied Petroleum Gas	7.20	7.53	7.10	6.78	7.99	7.46	6.75	8.16	7.25	6.38
Motor Gasoline[6]	9.23	10.14	9.88	9.54	10.28	9.90	9.09	10.30	9.58	8.61
Residual Fuel	2.55	3.10	2.92	2.72	3.44	3.15	2.74	3.53	3.11	2.62
Natural Gas	3.57	3.73	3.43	3.14	3.99	3.41	2.83	4.29	3.47	2.66
Coal	1.36	1.39	1.27	1.17	1.38	1.22	1.08	1.37	1.14	0.96
E85[8]	11.95	16.92	16.71	15.43	17.65	17.61	14.27	17.61	17.64	13.97
Electricity	20.89	20.02	19.56	19.16	20.08	19.23	18.52	19.89	18.60	17.63

[1]Excludes independent power producers.
[2]Includes cogenerators.
[3]Excludes uses for lease and plant fuel.
[4]Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[5]Kerosene-type jet fuel.
[6]Sales weighted-average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[7]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[8]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[9]Includes all electric power generators except cogenerators, which produce electricity as a by-product of other processes.
[10]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: 1995 figures may differ from published data due to internal rounding.

Sources: 1995 prices for gasoline, distillate, and jet fuel are based on prices in various 1995 issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(95/1-12) (Washington, DC, 1995). 1995 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditure Report 1993*, DOE/EIA-0376(93) (Washington, DC, December 1995). 1995 industrial gas delivered prices are based on EIA, *Manufacturing Energy Consumption Survey 1991*. 1995 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(96/6) (Washington, DC, June 1996). Other 1995 natural gas delivered prices: EIA, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology). Values for 1995 coal prices have been estimated from EIA, *State Energy Price and Expenditure Report 1993*, DOE/EIA-0376(93) (Washington, DC, December 1995) by use of consumption quantities aggregated from EIA, *State Energy Data Report 1993, Consumption Estimates*, DOE/EIA-0214(93) (Washington, DC, July 1995). 1995 electricity prices for commercial, industrial, and transportation: EIA, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology). **Projections:** EIA, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology).

Table A4. Residential Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Household Characteristics										
Households (millions)										
Single-Family	68.66	76.84	76.85	76.88	80.90	80.92	80.95	85.04	85.07	85.10
Multifamily	24.56	26.97	26.98	27.00	28.63	28.67	28.71	30.39	30.45	30.50
Mobile Homes	5.83	6.63	6.64	6.64	6.89	6.89	6.89	7.12	7.12	7.12
Total	**99.06**	**110.44**	**110.47**	**110.52**	**116.42**	**116.48**	**116.55**	**122.56**	**122.65**	**122.73**
Housing Starts (millions)										
Single-Family	1.08	1.08	1.08	1.08	1.03	1.03	1.03	1.09	1.09	1.09
Multifamily	0.28	0.42	0.42	0.43	0.47	0.48	0.48	0.48	0.48	0.48
Mobile Homes	0.34	0.29	0.29	0.29	0.28	0.28	0.28	0.29	0.29	0.29
Total	**1.70**	**1.79**	**1.80**	**1.81**	**1.78**	**1.79**	**1.79**	**1.86**	**1.86**	**1.86**
Average House Square Footage	**1643**	**1683**	**1683**	**1683**	**1696**	**1696**	**1696**	**1708**	**1708**	**1707**
Energy Intensity										
Million Btu Consumed per Household										
Delivered Energy Consumption	106.09	105.84	103.82	103.15	105.54	101.98	101.52	106.28	102.16	100.49
Electricity Related Losses	79.93	80.72	77.64	76.34	82.59	77.12	75.66	84.75	75.70	73.85
Total Energy Consumption	186.02	186.56	181.46	179.50	188.14	179.11	177.18	191.03	177.87	174.35
Thousand Btu Consumed per Square Foot										
Delivered Energy Consumption	64.57	62.87	61.67	61.28	62.21	60.12	59.85	62.23	59.83	58.86
Electricity Related Losses	48.65	47.95	46.12	45.35	48.68	45.46	44.60	49.63	44.33	43.25
Total Energy Consumption	113.22	110.82	107.79	106.63	110.90	105.58	104.45	111.86	104.16	102.11
Delivered Energy Consumption by Fuel										
Distillate										
Space Heating	0.76	0.71	0.69	0.67	0.70	0.65	0.64	0.69	0.63	0.61
Water Heating	0.09	0.10	0.10	0.10	0.09	0.10	0.10	0.09	0.10	0.10
Other Uses[1]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Energy	**0.85**	**0.81**	**0.79**	**0.77**	**0.80**	**0.75**	**0.74**	**0.79**	**0.73**	**0.71**
Liquefied Petroleum Gas										
Space Heating	0.30	0.33	0.32	0.31	0.34	0.32	0.31	0.36	0.32	0.31
Water Heating	0.06	0.08	0.08	0.08	0.09	0.09	0.09	0.10	0.09	0.10
Cooking[2]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Other Uses[3]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Delivered Energy	**0.40**	**0.45**	**0.44**	**0.43**	**0.47**	**0.45**	**0.44**	**0.49**	**0.45**	**0.44**
Natural Gas										
Space Heating	3.48	3.89	3.80	3.79	4.06	3.88	3.88	4.26	3.97	3.95
Space Cooling	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02
Water Heating	1.25	1.35	1.33	1.38	1.40	1.38	1.45	1.45	1.57	1.53
Cooking[2]	0.15	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.15
Clothes Dryers	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Other Uses[3]	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.11	0.11	0.11
Delivered Energy	**5.01**	**5.54**	**5.43**	**5.47**	**5.77**	**5.57**	**5.65**	**6.04**	**5.87**	**5.81**
Electricity										
Space Heating	0.43	0.48	0.47	0.46	0.50	0.48	0.46	0.53	0.49	0.46
Space Cooling	0.48	0.49	0.48	0.47	0.51	0.49	0.45	0.55	0.50	0.43
Water Heating	0.35	0.37	0.37	0.37	0.38	0.38	0.39	0.39	0.39	0.40
Refrigeration	0.40	0.33	0.33	0.33	0.33	0.32	0.30	0.34	0.32	0.29
Cooking	0.12	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.15
Clothes Dryers	0.18	0.20	0.20	0.20	0.21	0.21	0.21	0.22	0.22	0.22
Freezers	0.13	0.09	0.09	0.09	0.08	0.08	0.08	0.07	0.08	0.08
Lighting	0.31	0.36	0.34	0.27	0.38	0.35	0.29	0.41	0.36	0.31
Other Uses[4]	1.15	1.75	1.73	1.76	2.03	2.02	2.06	2.36	2.35	2.42
Delivered Energy	**3.56**	**4.20**	**4.14**	**4.07**	**4.56**	**4.45**	**4.37**	**5.02**	**4.84**	**4.76**

Table A4. Residential Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Marketed Renewables										
Wood[5]	0.57	0.57	0.56	0.54	0.57	0.55	0.52	0.58	0.54	0.51
Delivered Energy	**0.57**	**0.57**	**0.56**	**0.54**	**0.57**	**0.55**	**0.52**	**0.58**	**0.54**	**0.51**
Other Fuels[6]	**0.13**	**0.12**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.10**	**0.10**
Delivered Energy Consumption by End-Use										
Space Heating	5.65	6.11	5.94	5.88	6.30	5.98	5.92	6.53	6.05	5.94
Space Cooling	0.48	0.50	0.49	0.48	0.53	0.50	0.46	0.57	0.52	0.45
Water Heating	1.75	1.90	1.88	1.93	1.96	1.95	2.02	2.04	2.15	2.13
Refrigeration	0.40	0.33	0.33	0.33	0.33	0.32	0.30	0.34	0.32	0.29
Cooking	0.30	0.30	0.30	0.31	0.31	0.30	0.31	0.31	0.31	0.32
Clothes Dryers	0.23	0.25	0.24	0.25	0.26	0.26	0.26	0.27	0.27	0.28
Freezers	0.13	0.09	0.09	0.09	0.08	0.08	0.08	0.07	0.08	0.08
Lighting	0.31	0.36	0.34	0.27	0.38	0.35	0.29	0.41	0.36	0.31
Other Uses[7]	1.24	1.86	1.84	1.87	2.15	2.14	2.18	2.48	2.47	2.54
Delivered Energy	**10.51**	**11.69**	**11.47**	**11.40**	**12.29**	**11.88**	**11.83**	**13.03**	**12.53**	**12.33**
Electricity Related Losses by End-Use										
Space Heating	0.95	1.03	0.97	0.95	1.06	0.96	0.93	1.10	0.94	0.88
Space Cooling	1.07	1.04	0.99	0.96	1.08	0.98	0.90	1.13	0.96	0.82
Water Heating	0.78	0.78	0.76	0.77	0.80	0.76	0.78	0.81	0.75	0.77
Refrigeration	0.90	0.71	0.69	0.68	0.70	0.65	0.61	0.70	0.61	0.55
Cooking	0.27	0.28	0.27	0.28	0.29	0.27	0.28	0.30	0.27	0.28
Clothes Dryers	0.40	0.42	0.41	0.41	0.44	0.42	0.43	0.45	0.42	0.43
Freezers	0.29	0.18	0.19	0.18	0.16	0.16	0.16	0.15	0.15	0.14
Lighting	0.70	0.76	0.71	0.55	0.80	0.71	0.58	0.84	0.69	0.58
Other Uses[7]	2.55	3.71	3.59	3.65	4.28	4.07	4.16	4.89	4.50	4.61
Total Electricity Related Losses	**7.92**	**8.91**	**8.58**	**8.44**	**9.62**	**8.98**	**8.82**	**10.39**	**9.28**	**9.06**
Total Energy Consumption by End-Use										
Space Heating	6.60	7.13	6.91	6.83	7.36	6.94	6.85	7.63	6.98	6.82
Space Cooling	1.55	1.54	1.48	1.44	1.61	1.48	1.36	1.71	1.48	1.27
Water Heating	2.53	2.68	2.64	2.70	2.76	2.71	2.80	2.85	2.90	2.89
Refrigeration	1.30	1.04	1.03	1.01	1.02	0.97	0.91	1.04	0.92	0.84
Cooking	0.58	0.58	0.57	0.58	0.60	0.58	0.59	0.61	0.58	0.60
Clothes Dryers	0.63	0.67	0.65	0.66	0.70	0.67	0.69	0.72	0.69	0.71
Freezers	0.42	0.27	0.27	0.27	0.24	0.24	0.24	0.23	0.23	0.22
Lighting	1.02	1.12	1.06	0.82	1.18	1.07	0.86	1.24	1.05	0.89
Other Uses[7]	3.79	5.56	5.44	5.52	6.42	6.21	6.34	7.38	6.98	7.15
Total	**18.43**	**20.60**	**20.05**	**19.84**	**21.90**	**20.86**	**20.65**	**23.41**	**21.81**	**21.40**
Non-Marketed Renewables										
Geothermal[8]	0.01	0.04	0.04	0.04	0.05	0.05	0.05	0.07	0.07	0.07
Solar[9]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Total	**0.02**	**0.05**	**0.05**	**0.05**	**0.06**	**0.06**	**0.06**	**0.08**	**0.08**	**0.08**

[1]Includes such appliances as swimming pool and hot tub heaters.
[2]Does not include outdoor grills.
[3]Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).
[4]Includes such appliances as microwave ovens, television sets, and dishwashers.
[5]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 1993*.
[6]Includes kerosene and coal.
[7]Includes such appliances as swimming pool heaters, hot tub heaters, outdoor grills, outdoor lighting (natural gas), microwave ovens, television sets, and dishwashers.
[8]Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.
[9]Includes primary energy displaced by solar thermal water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995: Energy Information Administration (EIA), *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). **Projections:** EIA, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology).

Table A5. Commercial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Key Indicators										
Total Floor Space (billion square feet)										
Surviving	68.9	76.0	76.0	76.0	79.1	79.1	79.2	82.4	82.5	82.5
New Additions	1.7	1.5	1.5	1.5	1.6	1.6	1.6	1.8	1.8	1.8
Total	**70.7**	**77.5**	**77.5**	**77.5**	**80.7**	**80.7**	**80.8**	**84.2**	**84.2**	**84.3**
Energy Consumption Intensity (thousand Btu per square foot)										
Delivered Energy Consumption	101.2	101.8	101.3	101.3	101.7	100.8	100.9	102.1	100.9	101.1
Electricity Related Losses	101.6	102.9	99.4	99.1	104.0	97.8	97.2	104.3	94.7	93.4
Total Energy Consumption	202.8	204.7	200.7	200.4	205.7	198.6	198.1	206.4	195.6	194.6
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.11	0.12	0.12	0.12	0.13	0.13	0.12	0.14	0.13	0.13
Space Cooling	0.58	0.53	0.53	0.53	0.53	0.53	0.54	0.54	0.55	0.55
Water Heating	0.17	0.16	0.15	0.15	0.15	0.14	0.14	0.15	0.13	0.13
Ventilation	0.17	0.18	0.18	0.18	0.19	0.19	0.19	0.19	0.20	0.20
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Lighting	1.21	1.34	1.32	1.30	1.37	1.32	1.28	1.41	1.35	1.32
Refrigeration	0.14	0.16	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0.17
Office Equipment (PC)	0.07	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.10	0.10
Office Equipment (non-PC)	0.18	0.22	0.22	0.22	0.25	0.25	0.25	0.27	0.27	0.27
Other Uses[1]	0.56	0.92	0.92	0.92	1.08	1.08	1.08	1.23	1.24	1.24
Delivered Energy	**3.23**	**3.75**	**3.72**	**3.71**	**3.98**	**3.92**	**3.89**	**4.24**	**4.16**	**4.13**
Natural Gas[2]										
Space Heating	1.30	1.36	1.35	1.35	1.38	1.36	1.37	1.40	1.38	1.39
Space Cooling	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Water Heating	0.48	0.49	0.50	0.50	0.51	0.52	0.53	0.54	0.55	0.57
Cooking	0.18	0.21	0.21	0.22	0.22	0.23	0.24	0.24	0.25	0.26
Other Uses[3]	1.17	1.36	1.36	1.37	1.40	1.40	1.41	1.45	1.45	1.46
Delivered Energy	**3.16**	**3.45**	**3.45**	**3.46**	**3.54**	**3.54**	**3.58**	**3.66**	**3.66**	**3.71**
Distillate										
Space Heating	0.20	0.17	0.17	0.17	0.16	0.16	0.16	0.16	0.15	0.15
Water Heating	0.06	0.05	0.05	0.05	0.04	0.05	0.05	0.04	0.04	0.04
Other Uses[4]	0.15	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Delivered Energy	**0.41**	**0.36**	**0.36**	**0.36**	**0.35**	**0.35**	**0.35**	**0.34**	**0.34**	**0.34**
Other Fuels[5]	**0.35**	**0.32**	**0.32**	**0.32**	**0.33**	**0.33**	**0.33**	**0.34**	**0.34**	**0.34**
Marketed Renewable Fuels										
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Energy	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Delivered Energy Consumption by End-Use										
Space Heating	1.61	1.65	1.64	1.63	1.67	1.64	1.65	1.69	1.66	1.67
Space Cooling	0.61	0.56	0.56	0.56	0.56	0.56	0.57	0.57	0.58	0.58
Water Heating	0.70	0.70	0.70	0.70	0.71	0.70	0.72	0.73	0.72	0.74
Ventilation	0.17	0.18	0.18	0.18	0.19	0.19	0.19	0.19	0.20	0.20
Cooking	0.22	0.24	0.24	0.25	0.25	0.26	0.26	0.26	0.27	0.28
Lighting	1.21	1.34	1.32	1.30	1.37	1.32	1.28	1.41	1.35	1.32
Refrigeration	0.14	0.16	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0.17
Office Equipment (PC)	0.07	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.10	0.10
Office Equipment (non-PC)	0.18	0.22	0.22	0.22	0.25	0.25	0.25	0.27	0.27	0.27
Other Uses[6]	2.24	2.75	2.75	2.76	2.96	2.96	2.97	3.17	3.17	3.18
Delivered Energy	**7.15**	**7.89**	**7.85**	**7.86**	**8.21**	**8.14**	**8.15**	**8.59**	**8.50**	**8.52**

Table A5. Commercial Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Electricity Related Losses by End-Use										
Space Heating	0.25	0.26	0.25	0.25	0.27	0.25	0.25	0.28	0.25	0.24
Space Cooling	1.29	1.12	1.09	1.10	1.12	1.07	1.08	1.12	1.05	1.04
Water Heating	0.38	0.33	0.31	0.31	0.32	0.28	0.28	0.30	0.24	0.24
Ventilation	0.38	0.38	0.38	0.38	0.39	0.38	0.38	0.40	0.38	0.38
Cooking	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05
Lighting	2.68	2.85	2.73	2.70	2.88	2.65	2.59	2.92	2.59	2.51
Refrigeration	0.31	0.33	0.32	0.32	0.35	0.33	0.33	0.36	0.33	0.33
Office Equipment (PC)	0.16	0.20	0.20	0.20	0.21	0.20	0.20	0.22	0.20	0.20
Office Equipment (non-PC)	0.40	0.47	0.46	0.46	0.52	0.50	0.50	0.56	0.52	0.52
Other Uses[6]	1.24	1.96	1.91	1.91	2.28	2.18	2.18	2.55	2.37	2.35
Total Electricity Related Losses	**7.18**	**7.97**	**7.71**	**7.68**	**8.39**	**7.90**	**7.85**	**8.78**	**7.97**	**7.87**
Total Energy Consumption by End-Use										
Space Heating	1.87	1.91	1.89	1.88	1.94	1.90	1.90	1.97	1.91	1.92
Space Cooling	1.90	1.68	1.65	1.66	1.68	1.64	1.65	1.70	1.62	1.62
Water Heating	1.09	1.03	1.01	1.02	1.03	0.98	1.00	1.03	0.96	0.98
Ventilation	0.55	0.56	0.56	0.56	0.58	0.57	0.57	0.60	0.57	0.58
Cooking	0.29	0.30	0.30	0.31	0.31	0.31	0.32	0.32	0.33	0.34
Lighting	3.89	4.19	4.05	4.00	4.25	3.97	3.88	4.34	3.93	3.83
Refrigeration	0.46	0.49	0.47	0.47	0.51	0.49	0.49	0.54	0.51	0.50
Office Equipment (PC)	0.23	0.29	0.29	0.29	0.31	0.30	0.30	0.32	0.30	0.30
Office Equipment (non-PC)	0.59	0.70	0.68	0.68	0.76	0.74	0.74	0.84	0.79	0.79
Other Uses[6]	3.48	4.70	4.66	4.66	5.24	5.14	5.15	5.72	5.54	5.54
Total	**14.33**	**15.86**	**15.56**	**15.54**	**16.60**	**16.04**	**16.00**	**17.38**	**16.47**	**16.40**
Non-Marketed Renewable Fuels										
Solar[7]	0.01	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04
Total	**0.01**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**0.04**

[1]Includes miscellaneous uses, such as service station equipment, district services, automated teller machines, telecommunications equipment, and medical equipment.
[2]Excludes estimated consumption from independent power producers.
[3]Includes miscellaneous uses, such as district services, pumps, lighting, emergency electric generators, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, district services, and emergency electric generators.
[5]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[6]Includes miscellaneous uses, such as service station equipment, district services, automated teller machines, telecommunications equipment, medical equipment, pumps, lighting, emergency electric generators, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[7]Includes primary energy displaced by solar thermal water heaters.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995: Energy Information Administration (EIA), *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). **Projections:** EIA, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology).

Table A6. Industrial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Key Indicators										
Value of Gross Output (billion 1987 dollars)										
Manufacturing	2907	3696	3708	3720	4097	4116	4134	4412	4442	4467
Nonmanufacturing	765	914	917	919	974	977	980	1024	1029	1035
Total	**3672**	**4611**	**4625**	**4639**	**5071**	**5094**	**5115**	**5436**	**5471**	**5502**
Energy Prices (1995 dollars per million Btu)										
Electricity	14.6	13.88	13.58	13.18	13.85	13.31	12.65	13.57	12.72	11.83
Natural Gas	2.28	2.76	2.46	2.16	3.13	2.56	1.99	3.48	2.71	1.90
Steam Coal	1.49	1.58	1.45	1.33	1.60	1.38	1.21	1.62	1.30	1.10
Residual Oil	2.55	3.13	2.92	2.72	3.46	3.04	2.63	3.70	3.04	2.53
Distillate Oil	4.61	5.45	5.20	4.98	5.69	5.35	4.89	5.81	5.33	4.65
Liquefied Petroleum Gas	6.53	6.34	5.89	5.52	6.68	6.13	5.39	6.78	5.89	4.99
Motor Gasoline	9.18	9.01	8.74	8.41	9.31	8.93	8.13	9.47	8.75	7.78
Metallurgical Coal	1.76	1.81	1.74	1.60	1.81	1.59	1.46	1.82	1.48	1.33
Energy Consumption										
Consumption[1]										
Purchased Electricity	3.46	4.19	4.08	3.86	4.50	4.32	3.96	4.80	4.56	4.09
Natural Gas[2]	9.74	11.14	11.05	10.65	11.51	11.47	11.12	11.59	11.73	11.41
Steam Coal	1.59	1.84	1.74	1.56	2.03	1.86	1.52	2.25	2.06	1.55
Metallurgical Coal and Coke[3]	0.91	0.80	0.79	0.79	0.75	0.74	0.74	0.70	0.69	0.69
Residual Fuel	0.34	0.33	0.31	0.28	0.36	0.31	0.25	0.39	0.32	0.25
Distillate	1.15	1.38	1.39	1.35	1.48	1.48	1.41	1.55	1.55	1.46
Liquefied Petroleum Gas	2.01	2.27	2.21	2.11	2.38	2.30	2.15	2.47	2.36	2.19
Petrochemical Feedstocks	1.16	1.34	1.30	1.23	1.41	1.35	1.26	1.47	1.40	1.28
Other Petroleum[4]	4.03	4.75	4.61	4.49	4.97	4.77	4.51	5.18	4.79	4.48
Renewables[5]	1.74	2.13	2.12	2.11	2.29	2.29	2.26	2.43	2.42	2.37
Delivered Energy	**26.12**	**30.17**	**29.60**	**28.42**	**31.68**	**30.89**	**29.18**	**32.84**	**31.88**	**29.77**
Electricity Related Losses	7.69	8.91	8.46	8.00	9.48	8.71	7.98	9.94	8.74	7.79
Total	**33.81**	**39.08**	**38.06**	**36.42**	**41.16**	**39.60**	**37.16**	**42.78**	**40.62**	**37.56**
Consumption per Unit of Output[1] (thousand Btu per 1987 dollar)										
Purchased Electricity	0.94	0.91	0.88	0.83	0.89	0.85	0.77	0.88	0.83	0.74
Natural Gas[2]	2.65	2.42	2.39	2.30	2.27	2.25	2.17	2.13	2.14	2.07
Steam Coal	0.43	0.40	0.38	0.34	0.40	0.37	0.30	0.41	0.38	0.28
Metallurgical Coal and Coke[3]	0.25	0.17	0.17	0.17	0.15	0.15	0.14	0.13	0.13	0.12
Residual Fuel	0.09	0.07	0.07	0.06	0.07	0.06	0.05	0.07	0.06	0.04
Distillate	0.31	0.30	0.30	0.29	0.29	0.29	0.28	0.29	0.28	0.26
Liquefied Petroleum Gas	0.55	0.49	0.48	0.45	0.47	0.45	0.42	0.45	0.43	0.40
Petrochemical Feedstocks	0.32	0.29	0.28	0.27	0.28	0.27	0.25	0.27	0.26	0.23
Other Petroleum[4]	1.10	1.03	1.00	0.97	0.98	0.94	0.88	0.95	0.88	0.81
Renewables[5]	0.47	0.46	0.46	0.45	0.45	0.45	0.44	0.45	0.44	0.43
Delivered Energy	**7.11**	**6.54**	**6.40**	**6.13**	**6.25**	**6.06**	**5.71**	**6.04**	**5.83**	**5.41**
Electricity Related Losses	2.09	1.93	1.83	1.72	1.87	1.71	1.56	1.83	1.60	1.42
Total	**9.21**	**8.48**	**8.23**	**7.85**	**8.12**	**7.77**	**7.27**	**7.87**	**7.43**	**6.83**

[1]Fuel consumption includes consumption for cogeneration.
[2]Includes lease and plant fuel.
[3]Includes net coke coal imports.
[4]Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
[5]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995 prices for gasoline and distillate are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(95/3-96/4) (Washington, DC, 1995 - 1996). 1995 coal prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(96/08) (Washington, DC, August 1996). 1995 electricity prices: EIA, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology). 1995 prices derived from EIA, *State Energy Data Report 1993*, DOE/EIA-0214(93) (Washington, DC, July 1995). Other 1995 values: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). **Projections:** EIA, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology).

Table A7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Key Indicators										
Level of Travel (billions)										
Light-Duty Vehicles (vehicle miles traveled)	2208	2566	2571	2581	2755	2764	2785	2903	2921	2947
Freight Trucks (vehicle miles traveled)	166	219	219	221	236	237	240	249	250	253
Air (seat miles available)	931	1434	1441	1450	1655	1669	1684	1836	1856	1876
Rail (ton miles traveled)	1184	1365	1369	1383	1455	1463	1481	1531	1542	1568
Marine (ton miles traveled)	872	986	989	996	1043	1049	1060	1096	1105	1122
Energy Efficiency Indicators										
New Car (miles per gallon)[1]	27.5	29.7	29.7	31.5	30.5	31.4	34.6	30.3	32.5	36.0
New Light Truck (miles per gallon)[1]	20.5	21.4	21.4	22.9	22.0	22.7	26.2	21.9	24.0	28.4
Light-Duty Fleet (miles per gallon)[2]	19.7	19.8	19.8	20.1	20.2	20.3	21.4	20.7	21.2	23.0
Aircraft Efficiency (seat miles per gallon)	50.7	55.0	55.8	55.9	56.5	58.2	58.9	57.8	60.6	62.1
Freight Truck Efficiency (miles per gallon)	5.5	5.8	5.9	6.3	5.8	6.0	6.8	5.8	6.1	7.2
Rail Efficiency (ton miles per thousand Btu)	2.6	2.9	2.9	2.9	3.0	3.0	3.0	3.2	3.2	3.2
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.7	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0	3.0
Energy Use by Mode (quadrillion Btu per year)										
Light-Duty Vehicles	14.19	16.48	16.53	16.28	17.33	17.28	16.44	17.90	17.45	16.11
Freight Trucks	3.87	4.77	4.71	4.46	5.09	4.98	4.50	5.33	5.17	4.50
Air	3.18	4.18	4.15	4.16	4.64	4.55	4.54	4.99	4.83	4.77
Rail	0.48	0.51	0.51	0.51	0.52	0.52	0.52	0.52	0.52	0.53
Marine	1.63	2.09	2.09	2.10	2.29	2.30	2.31	2.45	2.47	2.48
Pipeline Fuel	0.72	0.82	0.84	0.84	0.86	0.88	0.91	0.88	0.93	0.97
Other[3]	0.21	0.27	0.27	0.27	0.29	0.29	0.29	0.29	0.30	0.30
Total	**24.31**	**29.25**	**29.24**	**28.74**	**31.18**	**30.96**	**29.65**	**32.54**	**31.83**	**29.82**

[1]Environmental Protection Agency rated miles per gallon.
[2]Combined car and light truck "on-the-road" estimate.
[3]Includes lubricants and aviation gasoline.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995: Federal Aviation Administration (FAA), *FAA Aviation Forecasts Fiscal Years 1993-2004*, (Washington, DC, February 1994); Energy Information Administration (EIA), *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996); EIA, *Fuel Oil and Kerosene Sales 1995*, DOE/EIA-0535(95) (Washington, DC, September 1996); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology).

Table A8. Electricity Supply, Disposition, and Prices
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Generation by Fuel Type										
Electric Generators[1]										
Coal	1671	2014	1866	1825	2207	1936	1845	2609	2054	1885
Petroleum	64	72	57	52	82	57	52	108	67	56
Natural Gas	322	557	656	611	662	848	799	688	1118	1132
Nuclear Power	673	654	654	654	614	614	614	448	448	448
Pumped Storage	-2	-3	-3	-3	-3	-3	-3	-3	-3	-3
Renewable Sources[2]	354	362	363	362	374	374	371	391	408	388
Total	**3083**	**3655**	**3592**	**3502**	**3935**	**3825**	**3678**	**4243**	**4092**	**3906**
Cogenerators[3]										
Coal	43	50	49	49	53	52	51	56	54	51
Petroleum	5	5	5	5	6	6	6	6	6	6
Natural Gas	180	207	207	208	219	217	215	229	224	220
Other Gaseous Fuels[4]	7	8	8	8	8	8	8	8	8	8
Renewable Sources[2]	42	50	50	49	54	53	52	58	56	54
Other[5]	3	4	3	3	4	4	4	4	4	4
Total	**279**	**323**	**322**	**323**	**343**	**340**	**335**	**361**	**351**	**342**
Sales to Utilities	148	160	160	160	165	164	162	170	167	164
Generation for Own Use	132	163	162	163	178	175	172	191	185	178
Net Imports	**38**	**40**	**38**	**33**	**37**	**33**	**30**	**33**	**29**	**27**
Electricity Sales by Sector										
Residential	1043	1230	1213	1193	1338	1306	1281	1471	1420	1394
Commercial	946	1100	1090	1087	1167	1148	1140	1244	1219	1211
Industrial	1013	1229	1196	1131	1318	1266	1160	1407	1337	1198
Transportation	6	15	15	15	24	24	21	30	30	25
Total	**3009**	**3573**	**3515**	**3426**	**3847**	**3744**	**3603**	**4152**	**4005**	**3828**
End-Use Prices (1995 cents per kilowatthour)[6]										
Residential	8.4	8.3	8.1	7.9	8.4	7.9	7.6	8.3	7.7	7.2
Commercial	8.0	7.5	7.4	7.2	7.5	7.3	7.0	7.4	7.0	6.6
Industrial	5.0	4.7	4.6	4.5	4.7	4.5	4.3	4.6	4.3	4.0
Transportation	5.2	5.0	5.0	5.0	5.0	4.9	4.9	4.8	4.7	4.7
All Sectors Average	**7.1**	**6.8**	**6.7**	**6.5**	**6.9**	**6.6**	**6.3**	**6.8**	**6.3**	**6.0**
Price Components (1995 cents per kilowatthour)										
Capital Component	2.7	2.6	2.5	2.5	2.5	2.4	2.4	2.4	2.2	2.2
Fuel Component	1.1	1.2	1.1	1.0	1.2	1.0	0.9	1.2	0.9	0.8
Operation and Maintenance Component	3.0	2.5	2.5	2.5	2.5	2.5	2.5	2.3	2.3	2.3
Wholesale Power Cost	0.4	0.6	0.6	0.6	0.7	0.7	0.6	0.9	0.9	0.7
Total	**7.1**	**6.8**	**6.7**	**6.5**	**6.9**	**6.6**	**6.3**	**6.8**	**6.3**	**6.0**

[1]Includes grid-connected generation at all utilities and nonutilities except for cogenerators. Includes small power producers, exempt wholesale generators, and generators at industrial and commercial facilities which provide electricity for on-site use and for sales to utilities.

[2]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar, and wind power.

[3]Includes cogeneration at facilities whose primary function is not electricity production. Includes sales to utilities and generation for own use.

[4]Other gaseous fuels include refinery and still gas.

[5]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.

[6]Prices represent average revenue per kilowatthour.

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

Sources: 1995 commercial and transportation sales derived from: Total transportation plus commercial sales come from Energy Information Administration (EIA), *State Energy Data Report 1993*, DOE/EIA-0214(93) (Washington, DC, July 1995), but individual sectors do not match because sales taken from commercial and placed in transportation, according to Oak Ridge National Laboratories, *Transportation Energy Data Book 15* (May 1995) which indicates the transportation value should be higher. 1995 generation by electric utilities, nonutilities, and cogenerators, net electricity imports, residential sales, and industrial sales: EIA, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). 1995 residential electricity prices derived from EIA, *Short Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). **1995 electricity prices for commercial, industrial, and transportation; price components; and projections:** EIA, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology).

Table A9. Electricity Generating Capability
(Thousand Megawatts)

Net Summer Capability[1]	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Electric Generators[2]										
Capability										
Coal Steam	304.9	315.9	300.6	298.2	340.1	303.8	298.3	399.5	316.1	299.5
Other Fossil Steam[3]	139.6	102.6	102.6	102.6	99.9	99.9	99.9	96.1	96.1	96.1
Combined Cycle	14.7	59.8	68.2	62.7	75.4	99.1	83.7	82.5	142.4	124.9
Combustion Turbine/Diesel	56.9	145.8	134.0	129.4	173.1	154.3	146.8	199.7	173.5	175.4
Nuclear Power	99.2	94.7	94.7	94.7	88.9	88.9	88.9	62.7	62.7	62.7
Pumped Storage	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9
Fuel Cells	0.0	0.0	1.8	0.9	0.0	2.1	2.0	0.0	2.4	2.4
Renewable Sources[4]	88.2	92.1	92.4	92.3	94.2	94.6	94.3	98.8	101.3	97.9
Total	**723.4**	**830.7**	**814.2**	**800.6**	**891.3**	**862.5**	**833.7**	**959.2**	**914.4**	**878.8**
Cumulative Planned Additions[5]										
Coal Steam	1.4	3.7	3.7	3.7	5.3	5.3	5.3	5.3	5.3	5.3
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	1.4	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Combustion Turbine/Diesel	3.2	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Nuclear Power	0.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Pumped Storage	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[4]	0.7	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Total	**8.0**	**15.5**	**15.5**	**15.5**	**17.1**	**17.1**	**17.1**	**17.1**	**17.1**	**17.1**
Cumulative Unplanned Additions[5]										
Coal Steam	0.0	27.2	11.9	9.5	52.4	17.1	11.5	115.8	33.2	16.6
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	44.2	52.7	47.2	59.9	83.6	68.2	67.0	126.9	109.4
Combustion Turbine/Diesel	1.1	89.5	77.7	73.1	117.1	98.3	90.9	144.9	118.7	120.5
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	1.8	0.9	0.0	2.1	2.0	0.0	2.4	2.4
Renewable Sources[4]	0.3	1.7	2.0	1.9	3.9	4.3	4.0	8.8	11.4	7.9
Total	**1.4**	**162.6**	**146.1**	**132.5**	**233.3**	**205.4**	**176.6**	**336.5**	**292.5**	**256.9**
Cumulative Total Additions	**9.4**	**178.1**	**161.6**	**148.0**	**250.4**	**222.5**	**193.7**	**353.6**	**309.6**	**274.0**
Cumulative Retirements[6]	**11.9**	**72.1**	**72.1**	**72.1**	**83.9**	**83.9**	**83.9**	**119.1**	**119.1**	**119.1**

Table A9. Electricity Generating Capability (Continued)
(Thousand Megawatts)

Net Summer Capability[1]	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Cogenerators[7]										
Capacity										
Coal	8.2	9.2	9.2	9.1	9.8	9.6	9.4	10.3	9.9	9.5
Petroleum	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0
Natural Gas	28.9	32.6	32.6	32.7	34.2	34.0	33.7	35.7	35.0	34.3
Other Gaseous Fuels	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Renewable Sources[4]	6.2	7.4	7.4	7.3	8.1	8.0	7.8	8.7	8.4	8.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**45.1**	**51.1**	**51.0**	**51.0**	**54.1**	**53.5**	**52.7**	**56.7**	**55.2**	**53.7**
Cumulative Additions[5]	**10.2**	**16.2**	**16.1**	**16.1**	**19.1**	**18.5**	**17.8**	**21.7**	**20.3**	**18.8**

[1]Net summer capability is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.

[2]Includes grid-connected utilities and nonutilities except for cogenerators. Includes small power producers, exempt wholesale generators, and generators at industrial and commercial facilities which produce electricity for on-site use and sales to utilities.

[3]Includes oil-, gas-, and dual-fired capability.

[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, other biomass, solar and wind power.

[5]Cumulative additions after December 31, 1994.

[6]Cumulative total retirements from 1990.

[7]Nameplate capacity is reported for nonutilities on Form EIA-867, "Annual Power Producer Report." Nameplate capacity is designated by the manufacturer. The nameplate capacity has been converted to the net summer capability based on historic relationships.

Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO97. Net summer capacity is used to be consistent with electric utility capacity estimates. Data for electric utility capacity are the most recent data available as of August 15, 1996. Therefore, capacity estimates may differ from other Energy Information Administration sources.

Sources: 1995 net summer capability at electric utilities and planned additions: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report." Net summer capability for nonutilities and cogeneration in 1995 and planned additions estimated based on EIA, Form EIA-867, "Annual Nonutility Power Producer Report." **Projections:** EIA, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology).

Table A10. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Crude Oil										
Domestic Crude Production[1]	6.56	5.13	5.47	5.89	4.75	5.40	6.09	4.52	5.27	6.19
Alaska	1.48	0.85	0.94	1.03	0.65	0.77	0.91	0.59	0.64	0.79
Lower 48 States	5.08	4.28	4.53	4.86	4.10	4.62	5.18	3.94	4.63	5.39
Net Imports	7.14	9.87	9.53	9.07	10.52	9.90	9.17	10.95	10.20	9.23
Other Crude Supply[2]	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**13.97**	**15.00**	**15.00**	**14.96**	**15.27**	**15.29**	**15.26**	**15.47**	**15.47**	**15.42**
Natural Gas Plant Liquids	**1.76**	**2.08**	**2.10**	**2.04**	**2.21**	**2.25**	**2.21**	**2.25**	**2.43**	**2.43**
Other Inputs[3]	**0.46**	**0.24**	**0.24**	**0.24**	**0.23**	**0.21**	**0.22**	**0.22**	**0.21**	**0.24**
Refinery Processing Gain[4]	**0.77**	**0.80**	**0.78**	**0.78**	**0.85**	**0.81**	**0.79**	**0.78**	**0.76**	**0.75**
Net Product Imports[5]	**0.75**	**2.75**	**2.51**	**2.13**	**3.48**	**3.04**	**2.08**	**4.31**	**3.23**	**1.77**
Total Primary Supply[6]	**17.73**	**20.87**	**20.64**	**20.15**	**22.05**	**21.59**	**20.56**	**23.04**	**22.10**	**20.61**
Refined Petroleum Products Supplied										
Motor Gasoline[7]	7.81	8.91	8.94	8.80	9.26	9.23	8.79	9.49	9.26	8.57
Jet Fuel[8]	1.51	2.00	1.99	1.99	2.22	2.18	2.17	2.38	2.31	2.28
Distillate Fuel[9]	3.25	3.84	3.80	3.65	4.06	3.99	3.73	4.23	4.12	3.77
Residual Fuel	0.85	1.10	1.03	1.00	1.23	1.10	1.05	1.40	1.19	1.11
Other[10]	4.32	5.04	4.90	4.74	5.31	5.11	4.83	5.54	5.23	4.88
Total	**17.73**	**20.89**	**20.66**	**20.18**	**22.07**	**21.61**	**20.58**	**23.06**	**22.11**	**20.61**
Refined Petroleum Products Supplied										
Residential and Commercial	1.07	1.05	1.03	1.02	1.06	1.02	1.00	1.07	1.01	0.99
Industrial[11]	4.58	5.29	5.16	4.97	5.56	5.37	5.04	5.80	5.49	5.09
Transportation	11.79	14.23	14.21	13.97	15.09	14.97	14.31	15.70	15.32	14.29
Electric Generators[12]	0.30	0.32	0.25	0.23	0.37	0.25	0.23	0.49	0.29	0.25
Total	**17.73**	**20.89**	**20.66**	**20.18**	**22.07**	**21.61**	**20.58**	**23.06**	**22.11**	**20.61**
Discrepancy[13]	**-0.01**	**-0.02**	**-0.02**	**-0.03**	**-0.03**	**-0.01**	**-0.01**	**-0.02**	**-0.01**	**-0.01**
World Oil Price (1995 dollars per barrel)[14]	**17.26**	**20.72**	**19.74**	**18.62**	**22.03**	**20.53**	**18.27**	**23.26**	**21.13**	**18.24**
Import Share of Product Supplied	**0.44**	**0.60**	**0.58**	**0.56**	**0.63**	**0.60**	**0.55**	**0.66**	**0.61**	**0.53**
Expenditures for Imported Crude Oil and Petroleum Products (billion 1995 dollars)	**49.39**	**94.24**	**85.50**	**74.48**	**112.49**	**96.33**	**73.71**	**127.89**	**102.02**	**70.79**
Domestic Refinery Distillation Capacity	**15.4**	**16.0**	**16.0**	**16.0**	**16.3**	**16.3**	**16.4**	**16.5**	**16.5**	**16.5**
Capacity Utilization Rate (percent)	**92.0**	**94.1**	**94.1**	**93.8**	**94.0**	**94.0**	**93.7**	**94.0**	**94.0**	**93.7**

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude products supplied.
[3]Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, and other hydrocarbons.
[4]Represents volumetric gain in refinery distillation and cracking processes.
[5]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net petroleum imports.
[7]Includes ethanol and ethers blended into gasoline.
[8]Includes naphtha and kerosene types.
[9]Includes distillate and kerosene.
[10]Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[11]Includes consumption by cogenerators.
[12]Includes all electric power generators except cogenerators, which produce electricity as a by-product of other processes.
[13]Balancing item. Includes unaccounted for supply, losses and gains.
[14]Average refiner acquisition cost for imported crude oil.

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

Sources: 1995 expenditures for imported crude oil and petroleum products based on internal calculations. Other 1995 data: Energy Information Administration (EIA), *Petroleum Supply Annual 1995*, DOE/EIA-0340(95) (Washington, DC, May 1996). **Projections:** EIA, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology).

Table A11. Petroleum Product Prices
(1995 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
World Oil Price (dollars per barrel)	**17.26**	**20.72**	**19.74**	**18.62**	**22.03**	**20.53**	**18.27**	**23.26**	**21.13**	**18.24**
Delivered Sector Product Prices										
Residential										
Distillate Fuel	86.5	104.3	100.7	97.7	107.7	102.6	96.2	108.4	102.1	92.8
Liquefied Petroleum Gas	88.8	101.2	98.0	95.7	105.9	101.6	95.3	107.9	99.9	92.4
Commercial										
Distillate Fuel	60.8	76.6	73.0	70.0	79.7	74.9	68.4	80.7	74.3	64.9
Residual Fuel	44.7	46.1	42.9	40.1	50.3	44.9	39.3	52.1	45.7	38.7
Residual Fuel (dollars per barrel)	18.78	19.36	18.03	16.86	21.13	18.85	16.51	21.88	19.18	16.25
Industrial [1]										
Distillate Fuel	63.9	75.6	72.1	69.0	78.9	74.2	67.8	80.6	73.9	64.4
Liquefied Petroleum Gas	56.4	54.7	50.8	47.6	57.6	52.9	46.5	58.5	50.9	43.0
Residual Fuel	38.2	46.8	43.7	40.7	51.7	45.5	39.4	55.3	45.5	37.8
Residual Fuel (dollars per barrel)	16.06	19.67	18.34	17.08	21.73	19.11	16.53	23.24	19.12	15.89
Transportation										
Distillate Fuel [2]	111.4	123.8	120.6	117.8	124.6	120.1	112.4	124.2	116.8	105.6
Jet Fuel [3]	52.0	76.0	72.6	69.1	80.1	74.7	66.5	81.4	73.1	63.3
Motor Gasoline[4]	114.8		122.4	118.2	127.3	122.7	112.7	127.5	118.7	106.8
Residual Fuel	36.5	46.2	43.5	40.6	51.5	47.4	41.3	52.0	46.7	39.2
Residual Fuel (dollars per barrel)	15.32	19.41	18.29	17.03	21.64	19.91	17.35	21.86	19.60	16.46
Electric Generators[5]										
Distillate Fuel	54.6	69.5	65.7	62.9	73.0	67.8	61.3	74.4	67.6	57.9
Residual Fuel	39.2	47.0	44.6	41.8	51.8	47.7	41.7	53.2	47.2	40.5
Residual Fuel (dollars per barrel)	16.46	19.73	18.75	17.55	21.75	20.03	17.53	22.34	19.84	17.01
Refined Petroleum Product Prices[6]										
Distillate Fuel [2]	96.8	110.8	107.5	104.4	112.6	107.8	100.1	112.6	105.4	94.1
Jet Fuel [3]	52.0	76.0	72.6	69.1	80.1	74.7	66.5	81.4	73.1	63.3
Liquefied Petroleum Gas	62.2	65.0	61.2	58.5	69.0	64.3	58.2	70.5	62.6	55.1
Motor Gasoline[4]	114.8	125.4	122.2	118.0	127.2	122.5	112.5	127.4	118.5	106.7
Residual Fuel	38.1	46.5	43.7	40.8	51.6	47.1	41.1	52.8	46.6	39.2
Residual Fuel (dollars per barrel)	16.01	19.52	18.37	17.12	21.65	19.78	17.24	22.16	19.56	16.47
Average	**92.4**	**102.8**	**99.9**	**96.4**	**104.8**	**100.6**	**92.0**	**104.7**	**97.2**	**86.4**

[1]Includes cogenerators.
[2]Includes Federal and State taxes on diesel fuel and excludes county and local taxes.
[3]Kerosene-type jet fuel.
[4]Sales weighted-average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[5]Includes all electric power generators except cogenerators, which produce electricity as a by-product of other processes.
[6]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.

Sources: 1995 prices for gasoline, distillate, and jet fuel are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(95/3-96/4) (Washington, DC, 1995-1996). 1995 prices for all other petroleum products are derived from EIA, *State Energy Price and Expenditures Report: 1993*, DOE/EIA-0376(93) (Washington, DC, December 1995). **Projections:** EIA, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology).

Table A12. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Production										
Dry Gas Production[1]	18.49	21.94	22.23	21.64	23.45	23.97	23.60	24.02	25.93	26.13
Supplemental Natural Gas[2]	0.13	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	**2.68**	**3.74**	**3.75**	**3.63**	**3.86**	**3.97**	**3.83**	**3.95**	**4.19**	**3.95**
Canada	2.79	3.58	3.58	3.46	3.68	3.79	3.65	3.77	4.01	3.78
Mexico	-0.05	-0.11	-0.11	-0.11	-0.12	-0.12	-0.12	-0.12	-0.12	-0.12
Liquefied Natural Gas	-0.05	0.27	0.27	0.27	0.29	0.29	0.29	0.29	0.29	0.29
Total Supply	**21.30**	**25.74**	**26.03**	**25.33**	**27.37**	**27.99**	**27.49**	**28.03**	**30.18**	**30.14**
Consumption by Sector										
Residential	4.87	5.39	5.28	5.32	5.61	5.41	5.49	5.87	5.70	5.65
Commercial	3.07	3.35	3.35	3.37	3.44	3.44	3.48	3.56	3.56	3.60
Industrial [3]	8.33	9.40	9.30	8.95	9.67	9.62	9.29	9.72	9.75	9.44
Electric Generators[4]	3.46	4.99	5.48	5.11	5.79	6.67	6.40	5.91	8.09	8.38
Lease and Plant Fuel [5]	1.14	1.42	1.43	1.40	1.51	1.53	1.51	1.55	1.65	1.65
Pipeline Fuel	0.70	0.80	0.81	0.82	0.84	0.86	0.88	0.85	0.90	0.95
Transportation[6]	0.01	0.18	0.18	0.17	0.25	0.25	0.23	0.30	0.30	0.26
Total	**21.58**	**25.52**	**25.84**	**25.14**	**27.11**	**27.79**	**27.29**	**27.76**	**29.95**	**29.93**
Discrepancy[7]	**-0.28**	**0.22**	**0.19**	**0.19**	**0.26**	**0.21**	**0.20**	**0.27**	**0.23**	**0.21**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity as a byproduct of other processes.
[5]Represents natural gas used in the field gathering and processing plant machinery.
[6]Compressed natural gas used as vehicle fuel.
[7]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 1995 values include net storage injections.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Figures for 1995 may differ from published data due to internal conversion factors.

Sources: 1995 supplemental natural gas: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(96/6) (Washington, DC, June 1996). 1995 imports and dry gas production derived from: EIA, *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC, November 1996). 1995 transportation sector consumption: EIA, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology). Other 1995 consumption: EIA, *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996) with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology). **Projections:** EIA, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology).

Table A13. Natural Gas Prices, Margins, and Revenue
(1995 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Source Price										
Average Lower 48 Wellhead Price[1]	1.61	2.13	1.86	1.58	2.51	1.95	1.41	2.87	2.09	1.31
Average Import Price	1.49	2.09	1.82	1.49	2.46	1.92	1.34	2.89	2.08	1.35
Average[2]	**1.59**	**2.12**	**1.85**	**1.57**	**2.51**	**1.95**	**1.40**	**2.88**	**2.09**	**1.32**
Delivered Prices										
Residential	6.18	5.84	5.57	5.21	5.90	5.38	4.70	6.01	5.26	4.43
Commercial	5.10	5.00	4.70	4.34	5.16	4.60	3.93	5.36	4.57	3.72
Industrial[3]	2.35	2.84	2.53	2.22	3.22	2.64	2.05	3.58	2.79	1.96
Electric Generators[4]	2.06	2.67	2.41	2.08	3.06	2.53	1.93	3.43	2.71	1.91
Transportation[5]	5.94	6.58	6.30	5.94	7.40	6.86	6.23	7.96	7.23	6.39
Average[6]	**3.67**	**3.84**	**3.52**	**3.22**	**4.10**	**3.50**	**2.91**	**4.41**	**3.56**	**2.73**
Transmission and Distribution Margins[7]										
Residential	4.59	3.72	3.72	3.64	3.39	3.44	3.30	3.14	3.17	3.11
Commercial	3.51	2.87	2.85	2.78	2.65	2.65	2.53	2.48	2.48	2.40
Industrial[3]	0.76	0.71	0.68	0.66	0.71	0.69	0.65	0.71	0.70	0.64
Electric Generators[4]	0.47	0.55	0.56	0.51	0.55	0.58	0.53	0.56	0.62	0.59
Transportation[5]	4.35	4.45	4.45	4.38	4.89	4.92	4.83	5.08	5.14	5.07
Average[6]	**2.08**	**1.71**	**1.67**	**1.66**	**1.60**	**1.56**	**1.51**	**1.54**	**1.47**	**1.41**
Transmission and Distribution Revenue (billion 1995 dollars)										
Residential	22.35	20.01	19.65	19.35	19.02	18.59	18.15	18.41	18.09	17.58
Commercial	10.79	9.64	9.56	9.35	9.14	9.12	8.81	8.83	8.83	8.66
Industrial[3]	6.31	6.71	6.34	5.89	6.90	6.61	6.02	6.89	6.78	6.04
Electric Generators[4]	1.61	2.74	3.05	2.60	3.18	3.90	3.38	3.30	5.05	4.95
Transportation[5]	0.04	0.79	0.79	0.76	1.22	1.23	1.12	1.53	1.52	1.34
Total	**41.11**	**39.88**	**39.39**	**37.96**	**39.46**	**39.45**	**37.48**	**38.95**	**40.27**	**38.57**

[1]Represents lower 48 onshore and offshore supplies.
[2]Quantity-weighted average of the average lower 48 wellhead price and the average price of imports at the U.S. border.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity as a by product of other processes.
[5]Compressed natural gas used as a vehicle fuel.
[6]Weighted average prices and margins. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
[7]Within the table, "transmission and distribution" margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term "transmission and distribution" margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.

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

Sources: 1995 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1991*. 1995 residential and commercial delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(96/6) (Washington, DC, June 1996). **Other 1995 values, and projections:** EIA, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology).

Table A14. Oil and Gas Supply

Production and Supply	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Crude Oil										
Lower 48 Average Wellhead Price[1]										
(1995 dollars per barrel)	**15.58**	**20.45**	**19.40**	**18.27**	**21.68**	**20.13**	**17.81**	**22.33**	**20.01**	**17.04**
Production (million barrels per day)[2]										
U.S. Total	**6.56**	**5.13**	**5.47**	**5.89**	**4.75**	**5.40**	**6.09**	**4.52**	**5.27**	**6.19**
Lower 48 Onshore	3.82	2.90	3.03	3.19	2.80	3.05	3.27	2.75	3.09	3.41
Conventional	3.24	2.32	2.43	2.57	2.12	2.36	2.58	1.99	2.34	2.68
Enhanced Oil Recovery	0.58	0.58	0.60	0.62	0.68	0.69	0.69	0.76	0.75	0.73
Lower 48 Offshore	1.26	1.38	1.50	1.67	1.30	1.57	1.91	1.19	1.54	1.99
Alaska	1.48	0.85	0.94	1.03	0.65	0.77	0.91	0.59	0.64	0.79
Lower 48 End of Year Reserves (billion barrels)	**17.18**	**14.25**	**15.24**	**16.52**	**13.78**	**15.55**	**17.41**	**13.49**	**15.70**	**18.14**
Natural Gas										
Lower 48 Average Wellhead Price[1]										
(1995 dollars per thousand cubic feet)	**1.61**	**2.13**	**1.86**	**1.58**	**2.51**	**1.95**	**1.41**	**2.87**	**2.09**	**1.31**
Production (trillion cubic feet)[3]										
U.S. Total	**18.48**	**21.94**	**22.23**	**21.65**	**23.44**	**23.97**	**23.60**	**24.02**	**25.93**	**26.14**
Lower 48 Onshore	13.00	15.82	15.49	14.29	17.78	16.94	15.28	18.62	18.43	16.71
Associated-Dissolved[4]	1.85	1.25	1.28	1.31	1.16	1.21	1.26	1.11	1.19	1.25
Non-Associated	11.15	14.57	14.22	12.98	16.62	15.72	14.02	17.52	17.24	15.46
Conventional	7.92	11.20	10.86	10.02	12.90	12.09	10.82	13.24	13.17	11.75
Unconventional	3.24	3.37	3.36	2.96	3.72	3.64	3.20	4.27	4.07	3.70
Lower 48 Offshore	5.05	5.60	6.21	6.84	5.12	6.48	7.77	4.82	6.93	8.85
Associated-Dissolved[4]	0.71	0.76	0.78	0.81	0.76	0.81	0.86	0.73	0.80	0.88
Non-Associated	4.34	4.84	5.43	6.03	4.36	5.67	6.91	4.09	6.13	7.97
Alaska	0.42	0.52	0.52	0.52	0.55	0.55	0.55	0.58	0.57	0.58
U.S. End of Year Reserves (trillion cubic feet)	**155.03**	**167.80**	**172.64**	**178.15**	**177.21**	**183.06**	**187.34**	**175.18**	**186.66**	**187.94**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.13**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**
Total Lower 48 Wells Completed (thousands)	**18.52**	**34.52**	**33.43**	**31.47**	**40.34**	**37.16**	**32.12**	**46.28**	**41.53**	**33.71**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Market production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Figures for 1995 may differ from published data due to internal conversion factors.
Sources: 1995 crude oil lower 48 average wellhead price: Energy Information Administration (EIA), Office of Integrated Analysis and Forecasting. 1995 total wells completed: EIA, Office of Integrated Analysis and Forecasting. 1995 lower 48 onshore, lower 48 offshore, Alaska crude oil production: EIA, *Petroleum Supply Annual 1995*, DOE/EIA-0340(95) (Washington, DC, May 1996). 1995 natural gas lower 48 average wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(96/06) (Washington, DC, June 1996). 1995 total natural gas production derived from: EIA, *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC, November 1996). Other 1995 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology).

Table A15. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Production[1]										
Appalachia	435	466	440	442	516	474	458	592	500	475
Interior	169	183	160	154	180	163	130	187	162	121
West	429	585	549	522	649	562	546	767	611	564
East of the Mississippi	544	587	538	537	631	572	527	714	592	535
West of the Mississippi	489	647	611	581	715	628	608	832	681	624
Total	**1033**	**1234**	**1149**	**1117**	**1346**	**1199**	**1134**	**1546**	**1273**	**1160**
Net Imports										
Imports	7	8	8	8	9	9	9	9	9	9
Exports	89	102	102	102	111	111	113	118	121	121
Total	**-81**	**-94**	**-94**	**-94**	**-102**	**-103**	**-105**	**-109**	**-112**	**-112**
Total Supply[2]	**951**	**1140**	**1055**	**1023**	**1244**	**1096**	**1030**	**1437**	**1161**	**1048**
Consumption by Sector										
Residential and Commercial	6	6	6	6	6	6	6	6	6	6
Industrial [3]	73	85	80	72	93	86	70	103	95	72
Coke Plants	33	26	26	26	23	23	23	20	20	20
Electric Generators[4]	847	1025	944	920	1123	982	931	1308	1040	950
Total	**959**	**1142**	**1055**	**1024**	**1245**	**1096**	**1030**	**1438**	**1161**	**1048**
Discrepancy and Stock Change[5]	**-8**	**-1**	**0**	**-1**	**-1**	**0**	**0**	**-1**	**0**	**-1**
Average Minemouth Price										
(1995 dollars per short ton)	18.90	20.09	17.76	15.76	20.01	16.93	14.12	20.28	15.57	12.12
(1995 dollars per million Btu)	0.88	0.96	0.85	0.75	0.96	0.81	0.67	0.98	0.75	0.58
Delivered Prices (1995 dollars per short ton)[6]										
Industrial	32.53	34.42	31.47	28.79	34.92	29.97	26.26	35.22	28.18	23.72
Coke Plants	47.24	48.39	46.70	42.81	48.59	42.55	39.08	48.80	39.56	35.55
Electric Generators										
(1995 dollars per short ton)	27.01	27.56	25.30	23.36	27.29	24.34	21.70	27.31	22.64	19.27
(1995 dollars per million Btu)	1.32	1.37	1.25	1.15	1.35	1.20	1.07	1.35	1.12	0.95
Average	**28.13**	**28.54**	**26.29**	**24.24**	**28.26**	**25.17**	**22.41**	**28.19**	**23.40**	**19.89**
Exports[7]	39.79	41.37	38.57	35.00	41.60	35.66	31.73	41.84	32.99	28.66

[1]Includes anthracite, bituminous coal, and lignite.
[2]Production plus net imports and net storage withdrawals.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity as a by-product of other processes.
[5]Balancing item: the sum of production, net imports, and net storage minus total consumption.
[6]Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.
[7]F.a.s. price at U.S. port of exit.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: 1995 data derived from: Energy Information Administration (EIA), *Coal Industry Annual 1994*, DOE/EIA-0584(94) (Washington, DC, October 1995). **Projections:** EIA, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology).

Table A16. Renewable Energy Generating Capacity and Generation
(Thousand Megawatts, Unless Otherwise Noted)

Capacity and Generation	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Electric Generators[1] (excluding cogenerators)										
Capability										
Conventional Hydropower	78.48	80.33	80.33	80.33	80.38	80.38	80.38	80.38	80.38	80.38
Geothermal [2]	2.97	3.11	3.15	2.99	3.84	3.30	2.90	4.23	3.82	2.88
Municipal Solid Waste	2.70	3.60	3.60	3.60	4.12	4.12	4.12	4.38	4.39	4.39
Wood and Other Biomass[3]	1.86	1.99	2.00	2.00	1.99	2.21	2.20	1.99	4.71	3.30
Solar Thermal	0.36	0.47	0.47	0.47	0.64	0.64	0.64	0.89	0.89	0.89
Solar Photovoltaic	0.01	0.13	0.13	0.13	0.35	0.35	0.35	0.67	0.67	0.67
Wind	1.83	2.48	2.72	2.77	2.84	3.57	3.67	6.22	6.45	5.35
Total	**88.22**	**92.09**	**92.39**	**92.28**	**94.15**	**94.57**	**94.26**	**98.76**	**101.30**	**97.87**
Generation (billion kilowatthours)										
Conventional Hydropower	309.82	303.59	303.57	303.53	304.13	304.09	304.03	304.27	304.20	304.13
Geothermal [2]	14.66	18.44	18.72	17.59	24.00	20.25	17.40	27.43	24.53	17.96
Municipal Solid Waste	18.69	24.11	24.11	24.12	27.70	27.71	27.70	29.56	29.56	29.55
Wood and Other Biomass[3]	7.12	9.15	9.22	9.23	9.15	10.75	10.66	9.15	28.19	18.38
Solar Thermal	0.82	1.25	1.25	1.25	1.80	1.80	1.80	2.61	2.61	2.61
Solar Photovoltaic	0.00	0.34	0.34	0.34	0.88	0.88	0.88	1.69	1.69	1.69
Wind	3.17	5.50	6.18	6.27	6.59	8.66	8.92	16.73	17.33	14.00
Total	**354.28**	**362.39**	**363.39**	**362.31**	**374.26**	**374.14**	**371.41**	**391.44**	**408.10**	**388.30**
Cogenerators[4]										
Capability										
Municipal Solid Waste	0.41	0.44	0.44	0.43	0.46	0.45	0.45	0.48	0.46	0.45
Biomass	5.79	7.00	6.96	6.91	7.66	7.51	7.33	8.24	7.93	7.58
Total	**6.19**	**7.44**	**7.40**	**7.35**	**8.11**	**7.96**	**7.78**	**8.71**	**8.40**	**8.03**
Generation (billion kilowatthours)										
Municipal Solid Waste	1.97	2.11	2.10	2.09	2.19	2.17	2.14	2.26	2.22	2.17
Biomass	39.58	47.84	47.57	47.24	52.21	51.23	50.03	56.11	54.08	51.70
Total	**41.55**	**49.94**	**49.68**	**49.33**	**54.40**	**53.41**	**52.18**	**58.37**	**56.30**	**53.87**

[1]Includes grid-connected utilities and nonutilities other than cogenerators. These nonutility facilities include small power producers, exempt wholesale generators and generators at industrial and commercial facilities which do not produce steam for other uses.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes projections for energy crops after 2010.
[4]Cogenerators are facilities whose primary function is not electricity production.

Notes: Totals may not equal sum of components due to independent rounding. Net summer capability has been estimated for nonutility generators for AEO97. Net summer capability is used to be consistent with electric utility capacity estimates. Data for electric utility capacity data are the most recently available data as of August 15, 1996. Additional retirements are also determined on the basis of the size and age of the units. Therefore, capacity estimates may differ from other Energy Information Administration sources.

Sources: 1995 electric utility capability: Energy Information Administration (EIA), Form EIA-860 "Annual Electric Utility Report." 1995 nonutility and cogenerator capability: Form EIA-867, "Annual Nonutility Power Producer Report." 1995 generation: EIA, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). **Projections:** EIA, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology).

Table A17. Renewable Energy, Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Marketed Renewable Energy[2]										
Residential	**0.57**	**0.57**	**0.56**	**0.54**	**0.57**	**0.55**	**0.52**	**0.58**	**0.54**	**0.51**
Wood	0.57	0.57	0.56	0.54	0.57	0.55	0.52	0.58	0.54	0.51
Commercial [3]	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial [4]	**1.74**	**2.13**	**2.12**	**2.11**	**2.29**	**2.29**	**2.26**	**2.43**	**2.42**	**2.37**
Conventional Hydroelectric	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Municipal Solid Waste	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Biomass	1.70	2.09	2.09	2.07	2.26	2.25	2.22	2.39	2.38	2.33
Transportation	**0.08**	**0.10**	**0.10**	**0.11**	**0.15**	**0.10**	**0.12**	**0.20**	**0.15**	**0.20**
Ethanol used in E85[5]	0.00	0.02	0.02	0.02	0.05	0.05	0.05	0.08	0.08	0.07
Ethanol used in Gasoline Blending	0.08	0.09	0.09	0.10	0.09	0.05	0.08	0.12	0.08	0.13
Electric Generators[6]	**3.99**	**4.22**	**4.23**	**4.20**	**4.50**	**4.41**	**4.32**	**4.79**	**4.88**	**4.53**
Conventional Hydroelectric	3.18	3.12	3.12	3.12	3.13	3.13	3.13	3.13	3.13	3.13
Geothermal	0.39	0.54	0.54	0.51	0.73	0.61	0.51	0.86	0.76	0.55
Municipal Solid Waste	0.31	0.39	0.39	0.39	0.45	0.45	0.45	0.48	0.48	0.48
Biomass	0.07	0.09	0.09	0.09	0.09	0.11	0.11	0.09	0.29	0.19
Solar Thermal	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.02	0.02	0.02
Wind	0.03	0.06	0.06	0.06	0.07	0.09	0.09	0.17	0.18	0.14
Total Marketed Renewable Energy	**6.37**	**7.02**	**7.02**	**6.97**	**7.52**	**7.36**	**7.23**	**7.99**	**7.99**	**7.61**
Non-Marketed Renewable Energy[7]										
Selected Consumption										
Residential	**0.02**	**0.05**	**0.05**	**0.05**	**0.06**	**0.06**	**0.06**	**0.08**	**0.08**	**0.08**
Solar Hot Water Heating	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Geothermal Heat Pumps	0.01	0.04	0.04	0.04	0.05	0.05	0.05	0.07	0.07	0.07
Commercial	**0.01**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**0.04**
Solar Thermal	0.01	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.
[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid.
[3]Value is less than 0.005 quadrillion Btu per year and rounds to zero.
[4]Includes all electricity production by industrial and other cogenerators for the grid and for own use.
[5]Excludes motor gasoline component of E85.
[6]Includes renewable energy delivered to the grid from electric utilities and nonutilities. Renewable energy used in generating electricity for own use is included in the individual sectoral electricity energy consumption values.
[7]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
Btu = British thermal unit.
Notes: Totals may not equal sum of components due to independent rounding.
Sources: 1995 electric generators: Energy Information Administration (EIA), Form EIA-860, “Annual Electric Utility Report,” and EIA, Form EIA-867, “Annual Nonutility Power Producer Report.” 1995 ethanol: EIA, *Petroleum Supply Annual 1995*, DOE/EIA-0340(95/1) (Washington, DC, May 1996). Other 1995: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology).

Table A18. Carbon Emissions by Sector and Source

(Million Metric Tons per Year, Unless Otherwise Noted)

Sector and Source	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Residential										
Petroleum	25.0	25.1	24.3	23.9	25.0	23.7	23.2	25.3	23.3	22.8
Natural Gas	72.1	79.8	78.2	78.8	83.1	80.2	81.4	87.0	84.5	83.7
Coal	1.4	1.2	1.2	1.1	1.2	1.1	1.1	1.1	1.1	1.0
Electricity	175.6	213.6	201.4	197.2	238.2	216.5	209.9	280.3	238.5	229.6
Total	**274.0**	**319.7**	**305.1**	**301.0**	**347.5**	**321.5**	**315.6**	**393.7**	**347.3**	**337.0**
Commercial										
Petroleum	13.4	11.8	11.8	11.8	11.8	11.7	11.7	11.7	11.6	11.7
Natural Gas	45.6	49.7	49.6	49.9	51.0	51.0	51.5	52.7	52.7	53.4
Coal	2.0	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.3
Electricity	159.2	191.1	181.0	179.6	207.9	190.4	186.8	237.1	204.8	199.4
Total	**220.2**	**254.7**	**244.6**	**243.4**	**272.9**	**255.3**	**252.3**	**303.9**	**271.5**	**266.8**
Industrial [1]										
Petroleum	92.4	105.9	105.6	102.4	111.1	110.0	103.6	116.2	112.0	104.0
Natural Gas[2]	138.5	158.3	157.2	151.6	163.5	163.4	158.3	164.7	166.9	162.5
Coal	62.8	64.1	61.6	56.9	67.0	62.8	54.1	70.8	66.0	53.2
Electricity	170.5	213.4	198.6	186.9	234.8	210.0	190.0	268.2	224.6	197.3
Total	**464.2**	**541.8**	**522.9**	**497.7**	**576.5**	**546.1**	**506.0**	**619.8**	**569.6**	**517.0**
Transportation										
Petroleum	453.5	542.6	542.0	532.2	575.7	571.8	546.2	599.0	585.3	545.6
Natural Gas[3]	10.5	14.4	14.7	14.6	16.1	16.4	16.5	17.1	17.8	18.0
Other[4]	0.0	0.4	0.4	0.4	1.0	1.0	1.0	1.5	1.5	1.3
Electricity	1.0	2.6	2.5	2.5	4.3	4.0	3.5	5.7	5.0	4.1
Total	**465.1**	**560.1**	**559.6**	**549.8**	**597.1**	**593.2**	**567.2**	**623.3**	**609.5**	**569.0**
Total Carbon Emissions[5]										
Petroleum	584.3	685.4	683.7	670.4	723.5	717.2	684.7	752.1	732.2	684.1
Natural Gas	266.7	302.2	299.8	294.9	313.8	311.0	307.7	321.5	321.8	317.6
Coal	66.2	67.5	64.9	60.2	70.5	66.1	57.4	74.2	69.4	56.5
Other[4]	0.0	0.4	0.4	0.4	1.0	1.0	1.0	1.5	1.5	1.3
Electricity	506.3	620.7	583.5	566.1	685.2	620.8	590.2	791.3	672.9	630.4
Total	**1423.6**	**1676.3**	**1632.2**	**1592.0**	**1794.0**	**1716.2**	**1641.0**	**1940.7**	**1797.9**	**1689.9**
Electric Generators[6]										
Petroleum	14.4	15.2	11.8	10.8	17.4	11.9	10.7	23.1	13.8	11.5
Natural Gas	50.9	73.4	80.6	75.3	85.2	98.2	94.1	87.0	119.1	123.3
Coal	441.1	532.1	491.1	480.1	582.7	510.7	485.3	681.2	540.0	495.6
Total	**506.3**	**620.7**	**583.5**	**566.1**	**685.2**	**620.8**	**590.2**	**791.3**	**672.9**	**630.4**
Total Carbon Emissions[7]										
Petroleum	598.7	700.6	695.5	681.1	740.9	729.1	695.5	775.2	746.0	695.6
Natural Gas	317.6	375.6	380.4	370.1	399.0	409.2	401.8	408.5	441.0	440.8
Coal	507.3	599.6	556.0	540.3	653.1	576.9	542.8	755.5	609.4	552.1
Other[4]	0.0	0.4	0.4	0.4	1.0	1.0	1.0	1.5	1.5	1.3
Total	**1423.6**	**1676.3**	**1632.2**	**1592.0**	**1794.0**	**1716.2**	**1641.0**	**1940.7**	**1797.9**	**1689.9**
Carbon Emissions (tons per person)	**5.4**	**5.8**	**5.7**	**5.5**	**6.0**	**5.7**	**5.5**	**6.2**	**5.8**	**5.4**

[1]Includes consumption by cogenerators.
[2]Includes lease and plant fuel.
[3]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[4]"Other" includes methanol and liquid hydrogen.
[5]Measured for delivered energy consumption.
[6]Includes all electric power generators except cogenerators, which produce electricity as a by-product of other processes.
[7]Measured for total energy consumption, with emissions for electric power generators distributed to the primary fuels.

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

Sources: Utility coal carbon emissions from Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States, 1987-1992*, DOE/EIA-0573 (Washington, DC, November 1994). Carbon coefficients from EIA, *Emissions of Greenhouse Gases in the United States 1995*, DOE/EIA-0573(95) (Washington, DC, October 1996). 1995 consumption estimates based on: EIA, *Short Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). **Projections:** EIA, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology).

Table A19. Macroeconomic Indicators
(Billion 1992 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
GDP Implicit Price Deflator (index 1992=1.000)	**1.076**	**1.413**	**1.411**	**1.408**	**1.672**	**1.667**	**1.661**	**1.995**	**1.987**	**1.979**
Real Gross Domestic Product	**6739**	**8372**	**8390**	**8415**	**9150**	**9182**	**9216**	**9833**	**9881**	**9925**
Real Consumption	4579	5659	5673	5692	6192	6217	6244	6671	6708	6742
Real Investment	1011	1358	1366	1375	1477	1487	1496	1578	1593	1606
Real Government Spending	1261	1363	1364	1366	1436	1440	1444	1492	1499	1505
Real Exports	775	1393	1396	1399	1715	1722	1731	2022	2036	2050
Real Imports	889	1387	1395	1405	1643	1660	1680	1890	1921	1949
Real Gross Domestic Product (1987 fixed-weighted dollars)	5677	7302	7318	7338	8116	8143	8171	8777	8818	8855
Real Disposable Personal Income (1987 fixed-weighted dollars)	**4047**	**5100**	**5113**	**5130**	**5618**	**5643**	**5670**	**6071**	**6109**	**6144**
Index of Manufacturing Gross Output (index 1987=1.000)	**1.246**	**1.584**	**1.589**	**1.595**	**1.756**	**1.764**	**1.772**	**1.891**	**1.904**	**1.915**
AA Utility Bond Rate (percent)	7.76	6.34	6.27	6.18	6.22	6.12	6.00	6.30	6.15	6.03
90-Day U.S. Government Treasury Bill Rate (percent)	5.49	4.33	4.32	4.31	4.13	4.15	4.18	3.99	4.04	4.08
Real Yield on Government 10 Year Bonds (percent)	5.22	2.07	2.07	2.07	1.39	1.35	1.30	1.31	1.24	1.15
Real 90-Day U.S. Government Treasury Bill Rate (percent)	2.94	1.07	1.10	1.13	0.66	0.71	0.76	0.29	0.35	0.40
Real Utility Bond Rate (percent)	5.21	3.08	3.05	3.00	2.75	2.67	2.58	2.60	2.46	2.34
Delivered Energy Intensity (thousand Btu per 1992 dollar of GDP)										
Delivered Energy	10.11	9.45	9.32	9.09	9.12	8.93	8.56	8.86	8.59	8.12
Total Energy	13.50	12.54	12.29	11.97	12.14	11.73	11.25	11.84	11.24	10.63
Consumer Price Index (1982-84=1.00)	1.52	2.09	2.08	2.07	2.51	2.49	2.48	3.04	3.01	2.99
Employment Cost Index (June 1989=1.00)	1.22	1.66	1.66	1.66	1.99	1.99	1.99	2.39	2.39	2.39
Unemployment Rate (percent)	5.59	5.72	5.63	5.52	5.81	5.71	5.63	5.79	5.66	5.56
Million Units										
Truck Deliveries, Light-Duty	6.10	6.95	7.03	7.12	7.23	7.31	7.41	7.61	7.73	7.84
Unit Sales of Automobiles	8.67	10.09	10.13	10.18	10.04	10.07	10.09	9.86	9.89	9.91
Millions of People										
Population with Armed Forces Overseas	263.6	287.1	287.1	287.1	298.9	298.9	298.9	311.2	311.2	311.2
Population (aged 16 and over)	202.1	223.8	223.8	223.8	235.4	235.4	235.4	245.8	245.8	245.8
Employment, Non-Agriculture	116.1	138.3	138.6	139.0	149.4	149.9	150.4	157.9	158.7	159.3
Employment, Manufacturing	18.2	18.1	18.1	18.2	17.9	17.9	18.0	17.3	17.4	17.5
Labor Force	132.3	149.7	149.7	149.8	157.2	157.3	157.4	161.0	161.1	161.2

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 1995: Data Resources Incorporated (DRI), DRI Trend0296. **Projections:** Energy Information Administration, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology).

Table A20. International Petroleum Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
World Oil Price (1995 dollars per barrel)[1]	**17.26**	**20.72**	**19.74**	**18.62**	**22.03**	**20.53**	**18.27**	**23.26**	**21.13**	**18.24**
Production[2]										
OECD										
U.S. (50 states)	9.29	8.26	8.60	8.95	8.09	8.71	9.37	7.88	8.76	9.70
Canada	2.44	2.47	2.46	2.46	2.35	2.35	2.34	2.25	2.24	2.22
Mexico	3.09	3.14	3.13	3.12	3.08	3.07	3.04	3.02	3.00	2.97
OECD Europe[3]	6.55	6.05	6.04	6.04	5.21	5.20	5.18	4.26	4.25	4.22
Other OECD	0.74	0.71	0.71	0.70	0.65	0.65	0.64	0.60	0.60	0.59
Total OECD	**22.11**	**20.62**	**20.94**	**21.27**	**19.39**	**19.98**	**20.57**	**18.02**	**18.84**	**19.70**
Developing Countries										
Other South & Central America	3.06	4.20	4.18	4.17	4.02	3.99	3.96	3.84	3.81	3.77
Pacific Rim	2.04	2.26	2.26	2.25	2.18	2.17	2.15	2.03	2.02	1.99
OPEC	28.07	42.31	42.16	41.81	50.82	50.65	50.31	60.54	60.25	60.11
Other Developing Countries	4.05	5.08	5.07	5.05	4.74	4.72	4.68	4.31	4.28	4.23
Total Developing Countries	**37.21**	**53.85**	**53.67**	**53.29**	**61.75**	**61.53**	**61.11**	**70.72**	**70.36**	**70.10**
Eurasia										
Former Soviet Union	6.96	8.36	8.34	8.32	9.48	9.43	9.36	10.17	10.09	9.97
Eastern Europe	0.31	0.23	0.23	0.23	0.21	0.21	0.21	0.18	0.18	0.18
China	3.02	3.05	3.04	3.04	3.02	3.00	2.98	2.97	2.95	2.91
Total Eurasia	**10.29**	**11.65**	**11.62**	**11.58**	**12.71**	**12.64**	**12.54**	**13.32**	**13.22**	**13.07**
Total Production	**69.62**	**86.13**	**86.23**	**86.14**	**93.85**	**94.15**	**94.23**	**102.06**	**102.42**	**102.86**
Consumption										
OECD										
U.S. (50 states)	17.73	20.90	20.66	20.18	22.07	21.60	20.57	23.01	22.11	20.62
U.S. Territories	0.26	0.34	0.35	0.35	0.37	0.38	0.39	0.40	0.42	0.44
Canada	1.76	1.99	2.01	2.04	2.10	2.14	2.21	2.22	2.29	2.39
Mexico	1.96	2.37	2.39	2.40	2.65	2.69	2.74	2.95	3.02	3.12
Japan	5.73	6.78	6.86	6.93	7.14	7.31	7.55	7.47	7.76	8.22
Australia and New Zealand	0.96	1.09	1.10	1.10	1.16	1.17	1.18	1.23	1.24	1.26
OECD Europe[3]	13.88	14.73	14.80	14.89	14.96	15.11	15.33	15.19	15.40	15.73
Total OECD	**42.28**	**48.21**	**48.16**	**47.90**	**50.45**	**50.40**	**49.98**	**52.47**	**52.24**	**51.77**
Developing Countries										
Other South and Central America	3.58	4.30	4.31	4.33	4.59	4.62	4.66	4.87	4.91	4.97
Pacific Rim	4.87	7.70	7.72	7.75	9.01	9.07	9.16	10.63	10.73	10.88
OPEC	4.94	6.30	6.30	6.30	7.06	7.06	7.06	7.91	7.91	7.91
Other Developing Countries	4.79	7.16	7.20	7.25	7.85	7.95	8.10	8.55	8.74	9.03
Total Developing Countries	**18.19**	**25.45**	**25.53**	**25.63**	**28.51**	**28.70**	**28.97**	**31.96**	**32.29**	**32.79**

Table A20. International Petroleum Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	1995	Projections								
		2005			2010			2015		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Eurasia										
Former Soviet Union	4.75	5.78	5.80	5.83	6.68	6.74	6.81	7.56	7.65	7.78
Eastern Europe	1.39	1.51	1.51	1.52	1.71	1.72	1.74	1.95	1.96	1.98
China	3.31	5.48	5.52	5.57	6.80	6.89	7.03	8.42	8.58	8.83
Total Eurasia	**9.46**	**12.77**	**12.83**	**12.92**	**15.20**	**15.35**	**15.58**	**17.94**	**18.19**	**18.60**
Total Consumption	**69.92**	**86.43**	**86.53**	**86.44**	**94.15**	**94.45**	**94.53**	**102.36**	**102.72**	**103.16**
Non-OPEC Production	41.55	43.81	44.07	44.33	43.03	43.50	43.91	41.53	42.17	42.75
Net Eurasia Exports	0.83	-1.12	-1.22	-1.33	-2.49	-2.71	-3.04	-4.61	-4.97	-5.53
OPEC Market Share	0.40	0.49	0.49	0.49	0.54	0.54	0.53	0.59	0.59	0.58

[1]Average refiner acquisition cost of imported crude oil.

[2]Includes production of crude oil (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol, liquids produced from coal and other sources, and refinery gains.

[3]OECD Europe includes the unified Germany.

OECD = Organization for Economic Cooperation and Development - Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States (including territories).

Pacific Rim = Hong Kong, Malaysia, Philippines, Singapore, South Korea, Taiwan, and Thailand.

OPEC = Organization of Petroleum Exporting Countries - Algeria, Gabon, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.

Eurasia = Albania, Bulgaria, China, Czech Republic, Hungary, Poland, Romania, Slovak Republic, the Former Soviet Union, and the Former Yugoslavia.

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

Sources: 1995 data derived from: Energy Information Administration (EIA), *Short-Term Energy Outlook*, DOE/EIA-0202(96/4Q) (Washington, DC, October 1996). **Projections:** EIA, AEO97 National Energy Modeling System runs ISS97LL.D032597A (Slow Technology), POLBASE.D032497A (Reference), and ISS97HH.D032597A (Rapid Technology).

Development Patterns for LNG Supply and Demand

by
Arthur T. Andersen, Linda E. Doman, and Arthur Rypinski

The following paper summarizes the prospects for liquefied natural gas (LNG) projects worldwide over the next decade. In addition to reviewing the current status of the world LNG market, the authors consider recent industry activity in such countries as Qatar, Oman, Nigeria, and Trinidad and Tobago and possible expansion beyond 2000. The paper suggests the possible locations of new and potential markets for LNG. It also attempts to explain the economic and technological factors that have limited the expansion of LNG market share. Conditions necessary to implement a successful LNG project are presented, as well as conditions that identify a country as a potential LNG consumer. The paper concludes with a discussion of the uncertainties associated with future LNG expansion.

Introduction

Natural gas is a highly desirable energy source: it burns cleanly, with little pollution; it is often inexpensive to produce and transport; and known proven reserves of natural gas are immense—some 4,900 trillion cubic feet worldwide at the end of 1995, enough for about 500 years of current world gas production.[1] Regrettably, much of the world's known natural gas reserves are inconveniently located in remote and thinly populated areas, such as Western Siberia and the Persian Gulf. The United States and Canada have been girdled with large gas pipelines that transport gas from the producing fields of Texas, Louisiana, Oklahoma, and Western Alberta to consuming markets in California and New England. At present, however, the technology does not exist to build long-distance pipelines through the depths of the ocean. Moving natural gas between continents requires an alternative approach.

Liquefied natural gas (LNG) is a proven commercial technology for transporting large volumes of natural gas across oceans. The international trade in LNG is now more than 30 years old. Today, LNG is being exported from eight countries (Indonesia, Algeria, Malaysia, Australia, Brunei, Abu Dhabi, the United States, and Libya) and imported into nine countries: United States (again), Japan, South Korea, Taiwan, Belgium, France, Spain, Italy, and Turkey. Despite the success of individual LNG projects, they account for only 4 percent of world natural gas consumption, and have thus far had only a marginal influence on world patterns of gas consumption. Many more LNG projects are possible than have actually come to fruition. Some projects have been under consideration for decades.

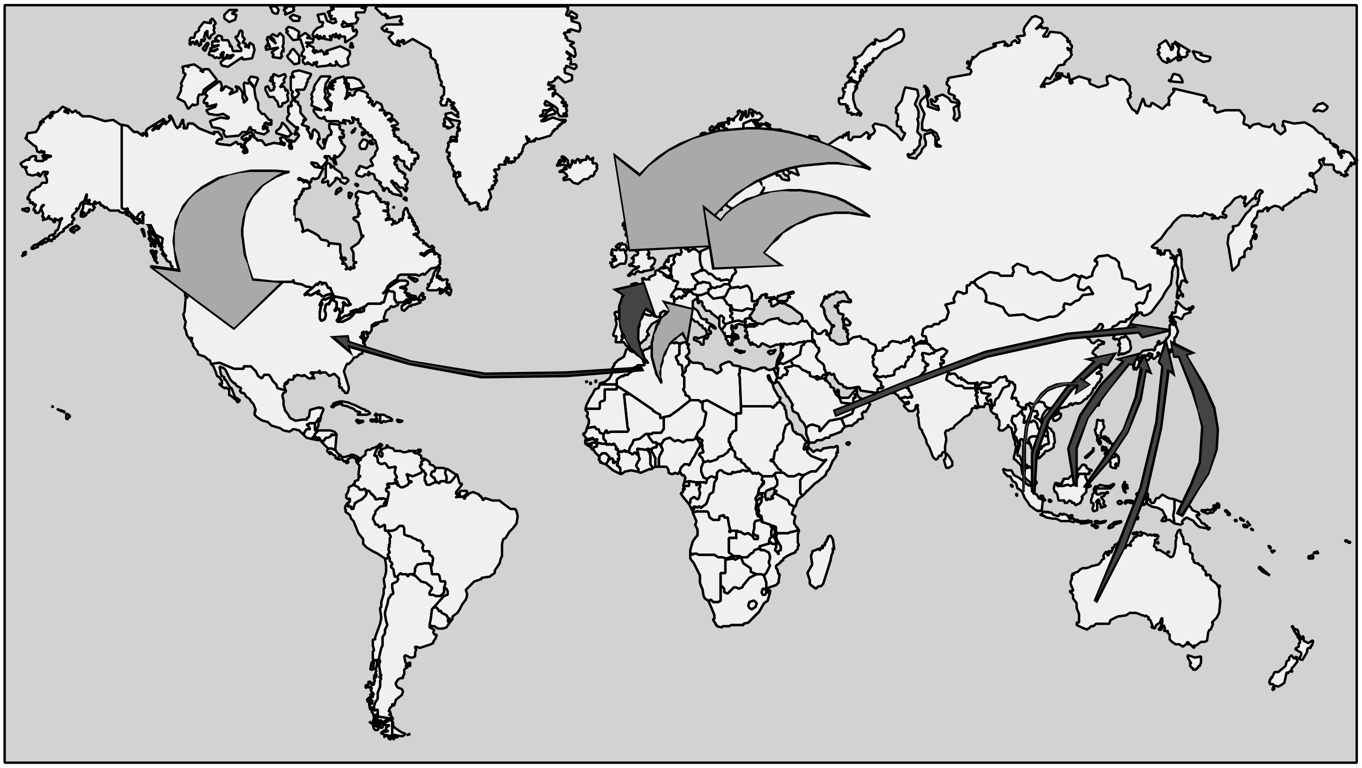
This paper summarizes prospects for worldwide LNG projects over the next decade and attempts to explain the economic and technological factors that have limited the expansion of LNG market share. These factors continue to be influential and will affect current and prospective projects.

Worldwide Natural Gas

According to the *International Energy Outlook 1997* (*IEO97*),[2] total world natural gas demand is expected to reach 145 trillion cubic feet by 2015, an 85-percent increase over the 1995 level of 78 trillion cubic feet. The *IEO97* does not identify the LNG portion of this consumption, because the model used to generate natural gas consumption projections does not distinguish the form gas takes before it is consumed. The *BP Statistical Review of World Energy 1996*[3] estimated that LNG represented 4.4 percent of the total world consumption of natural gas in 1995 (Figure 1).

[1]Energy Information Administration, *International Energy Annual 1995*, DOE/EIA-0219(95) (Washington, DC, December 1996), p. 108 (web site www.eia.doe.gov/emeu/iea/table81.html).
[2]Energy Information Administration, *International Energy Outlook 1997*, DOE/EIA-0484(97) (Washington, DC, April 1997).
[3]British Petroleum Company, *BP Statistical Review of World Energy 1996* (London, UK, June 1996), web site 165.121.20.76/bpstats.

Figure 1. World Natural Gas Trade Patterns, 1995



Note: Dark arrows represent LNG transport. Light arrows represent pipeline transport.

Source: British Petroleum Company, *BP Statistical Review of World Energy 1996* (London, UK, June 1996), web site 165.121.20.76/bpstats.

Natural gas use is growing rapidly worldwide, and LNG consumption appears to be increasing even more rapidly than that of piped gas, making it likely that the LNG share of total gas will rise over the next 10 to 15 years. LNG markets appear to be entering a new round of expansion, with a more diversified range of customers and suppliers. The largest proportion of increased LNG use will occur in Japan, South Korea, and several newly industrializing Asian countries, including India, Thailand, and perhaps China. There are a growing number of LNG supply contracts worldwide—despite the fact that average LNG prices tend to be higher than prices of competing fuels—primarily because it is environmentally a clean fuel (compared to coal and oil) and its markets tend to be where pipelines are unavailable.

Although gas inputs for LNG facilities are relatively cheap—based on large and easily produced reserves—processing and transportation equipment is capital intensive and highly specialized, requiring billions of dollars of investment for each new facility. For each million cubic feet of gas delivered to end use, less than 30 percent of the cost is associated with resource supply. The balance reflects the cost associated with processing and transportation.[4]

Existing liquefaction plants currently account for more than 4.0 trillion cubic feet of capacity per year (Table 1). Planned extensions to existing capacity involve additions of almost 1.4 trillion cubic feet of capacity. New projects under construction should add another 1.4 trillion cubic feet of capacity. Additional prospective capacity additions ranging between 1.4 and 4.3 trillion cubic feet between 1997 and beyond 2000 are in various stages of planing and negotiation.[5] Thus, it is possible that LNG processing capacity could nearly triple in the next decade or so.

[4]M.A. Adelman and M. Lynch, “Natural Gas Supply in the Asia-Pacific Basin,” in Massachusetts Institute of Technology Center for Energy Policy Research, *East Asia/Pacific Natural Gas Trade: Final Report*, 86-006 (Cambridge, MA, March 1986).

[5]*Petroleum Economist* in conjunction with Citibank, “Liquefaction Plants in the World: Extensions and New Projects,” in *LNG—Evolution and Development* (London, UK, 1996).

Table 1. Status of Worldwide LNG Capacity: Existing, Planned, and Potential as of 1996

Status of Capacity/Region	Capacity	
	Billion Cubic Feet per Year	Million Tons per Year
Existing Capacity		
North America	54	1.1
South America	0	—
Africa	1,081	22.2
Middle East	244	5.0
Asia	2,289	47.0
EE/FSU	0	—
Europe	0	—
World Existing Capacity	**4,047**	**83.1**
Expansions		
North America	0	—
South America	0	—
Africa	302	6.2
Middle East	0	—
Asia	721	14.8
EE/FSU	0	—
Europe	0	—
World Capacity Expansions	**1,403**	**28.8**
New Projects Under Construction		
North America	0	—
South America	141	2.9
Africa	287	5.9
Middle East	1,081	22.2
Asia	0	—
EE/FSU	0	—
Europe	0	—
World New Projects	**1,929**	**39.6**
In Negotiation/Proposed (post 2000) Capacity		
North America	682	14.0
South America	224	4.6
Africa	0	—
Middle East	731	15.0
Asia	1,656	34.0
EE/FSU	682	14.0
Europe	146	3.0
World Proposed Capacity	**4,120**	**84.6**
World Total Capacity, Existing and Proposed	**11,498**	**236.1**

Source: *Petroleum Economist* in conjunction with Citibank, "Liquefaction Plants in the World: Extensions and New Projects," in *LNG—Evolution and Development* (London, UK, 1996).

Sources of LNG

Historically the major sources of LNG supply have been Algeria, Australia, Indonesia, and Malaysia. These areas will continue to play a major role in LNG markets in the future, because available gas reserves are sufficient to support present producing capabilities and ongoing capacity expansion for many years to come. Malaysia and Indonesia together contributed nearly 89 percent of the new LNG capacity that came onstream in the early 1990s. Middle Eastern producers are expected to lead the next round of growth. Oman and Qatar will account for as much as 75 percent of additional capacity between 1997 and 2000. LNG supply diversity will be further enhanced when projects in Nigeria and Trinidad come online in 1999.[6,7] After 20 years in which only two greenfield LNG projects[8] came online, there are now four new projects at an advanced stage of development: Qatar's Ras Laffan LNG project, Trinidad, Oman, and Nigeria.[9] Other greenfield projects in advanced stages of planning include one each in Yemen, Russia's Sakhalin Island, and Western Canada.[10,11]

Only a small amount of LNG is currently exported from the United States, from Cook Inlet, Alaska. In 1995, about 56 billion cubic feet of LNG was supplied from the Alaskan facility to Japan.[12] However, the Yukon Pacific LNG Export Project has proposed construction of a new natural gas pipeline parallel to an existing crude oil line in Alaska, along with the construction of a gas liquefaction plant and marine terminal at Valdez.[13] The resulting LNG would be exported to Japan and Pacific Rim countries.

LNG Demand Growth

LNG is a major share of the total natural gas consumed in several countries of the world, particularly in Asia. Japan imports the largest amount of LNG, 63 percent of all LNG exports in 1995.[14] LNG accounts for more than 92 percent of Japan's total natural gas consumption.[15] The bulk of Japan's LNG currently comes from Indonesia, although supplies are also imported from Australia, Brunei, Malaysia, the United Arab Emirates, and the United States[16] (56 billion cubic feet). In 1996, Japan diversified its supplies even further by signing a long-term agreement with Qatar. The January 10, 1997 delivery of 65,000 tons (about 3.2 billion cubic feet) of LNG marked the entrance of Qatar into the industry.[17] Many analysts see the agreement between Qatargas and Chubu Electric Power of Japan as a major industry milestone. Qatargas is contracted to supply Chubu with up to 6 million tons of LNG per year (292 billion cubic feet) for a 25-year period. This is the first of three projects under way to export up to 12 million tons of gas (584 billion cubic feet) per year from Qatar's North Field by 2000. The second project, Ras Laffan LNG, is under construction and is scheduled to be onstream by mid-1999.

South Korea is the second largest consumer of LNG (following Japan) worldwide.[18] Virtually all natural gas consumed in South Korea is LNG. South Korea began importing LNG about 10 years ago in order to provide a clean alternative in the electric utility sector, and this sector has continued to provide much of the growth in gas consumption since that time.[19] About 10 percent of electricity generation in South Korea is attributable to gas.[20] The Korea Gas Corporation (Kogas) is currently increasing gas supplies to residential, commercial, and industrial users through 32 local gas and liquefied petroleum gas distributors.[21] Fifteen of these distributors already supply gas to end-use sectors other than electric utilities. In the future, the electric utility sector is expected (by Kogas) to lose share to (mostly) residential sector use because of rapid growth in this sector. The residential sector share of natural gas use is expected to grow from 34 percent to 40 percent between 1996 and 2010. Kogas plans to expand its gas trunkline from 2,200 miles to 3,700 miles by 2006. The company has estimated that LNG imports will more than triple between 1996 and 2010.

There is expanding interest in LNG resources in several other countries of developing Asia. Thailand and India, in particular, have made major plans for establishing LNG supplies. Thailand signed contracts with Oman to begin shipments of LNG in 2003.[22] At the end of 1996, India's state-owned Gas Authority of India, Ltd.,

[6]D. Knott, "OPEC States Seeking More Foreign Investment in Petroleum Sectors," *Oil & Gas Journal*, Vol. 94, No. 31 (July 29, 1996).
[7]"Atlantic LNG Seems Destined to Grow by Leaps and Bounds," *World Gas Intelligence*, Vol. 7, No. 20 (October 25, 1996), p. 4.
[8]A "greenfield" project is an industrial development in a rural area with no established infrastructure.
[9]"Feature: LNG Shifts Course for New Markets," *Financial Times International Gas Report*, No. 321 (April 18, 1997), pp. 35.
[10]"Gastech '96 in Vienna Was the Largest Yet," *Alexander's Gas & Oil Connections*, web site www.gasandoil.com (December 14, 1996).
[11]"Phillips with Others in West-Canadian LNG-Plant," *Alexander's Gas & Oil Connections*, web site www.gasandoil.com (April 9, 1997).
[12]British Petroleum Company, *BP Statistical Review of World Energy 1996* (London, UK, June 1996), p. 28, web site 165.121.20.76/bpstats.
[13]Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(96/11) (Washington, DC, November 1996), p. xiii.
[14]British Petroleum Company, *BP Statistical Review of World Energy 1996* (London, UK, June 1996), p. 28, web site 165.121.20.76/bpstats.
[15]British Petroleum Company, *BP Statistical Review of World Energy 1996* (London, UK, June 1996), pp. 26, 28, web site 165.121.20.76/bpstats.
[16]All U.S. LNG exports (from Cook Inlet, Alaska) went to Japan in 1995.
[17]V. Thomas, "LNG Shifts Course for New Markets," *Financial Times International Gas Report*, No. 321, p. 33.
[18]British Petroleum Company, *BP Statistical Review of World Energy* (London, UK, June 1996), p. 28, web site 165.121.20.76/bpstats.
[19]"Korea Weighs Import Alternatives to Feed Demand," *World Gas Intelligence*, Vol. 8, No. 6 (March 28, 1997), p. 9.
[20]WEFA Group, *Far East Report 1995*, p. 9.3.
[21]"Korea Weighs Import Alternatives to Feed Demand," *World Gas Intelligence*, Vol. 8, No. 6 (March 28, 1997), p. 9.
[22]"Reluctant Thailand Finally Ready for Plunge into LNG," *World Gas Intelligence*, Vol. 8, No. 5 (March 14, 1997), p. 1.

made an international call for LNG supplies as part of a $10 billion project to diversify its energy sources.[23] The government plans to set up two regasification plants, one at Ennore (near Madras, on India's southern coast) and one at Mangalore (western coast). India's Gas Authority has begun talks with Qatar's Ras Laffan LNG Company in an attempt to secure 5 million tons (244 billion cubic feet) of LNG for the planned projects.

Four more LNG import terminals could be developed in India besides the two planned at Ennore and Mangalore in the southern part of the country. Paradip and Visakhapatnam on the east coast and Kandla and new Mumbai on the west coast are locations for additional terminals for import of 2.5 million tons per year (122 billion cubic feet) each. Each could cost about $1.1 billion, and all the new terminals could be online by 2005. India would like to import LNG both from Persian Gulf and southeast Asian countries. The government has identified LNG as a long-term fuel for the electric power sector.

Even China may emerge as a market for LNG. Shanghai is seeking foreign funds and technology to help build a $300 million LNG storage unit.[24] The city wants to reduce its reliance on coal in favor of cleaner energy sources. According to the Shanghai Planning Commission, coal currently meets 72 percent of Shanghai's fuel needs, and consumption is projected to reach 60 million tons per year by 2000 and 90 million tons per year by 2010. To diversify fuel use, Shanghai would import 3 million metric tons (146 billion cubic feet) of LNG per year to meet its requirements. A prospective LNG project would take an estimated 5 years to complete and would import gas from countries in Southeast Asia and Australasia.

European buyers of LNG include Western European countries: Turkey, France, Belgium, and Spain.[25] In Spain, LNG accounted for 81 percent of the country's total natural gas consumption in 1995. However, pipeline connections to Algeria and to the European grid will cause LNG to lose out to conventional gas sources in coming years. Demand for LNG in Western Europe may grow by as much as 155 million tons (7.5 trillion cubic feet) per year by 2010, around 90 tons (4.4 trillion cubic feet) of which would be covered by existing supply contracts.[26] Some 50 million tons (2.4 trillion cubic feet) of European LNG demand could be met by supplies from the Middle East. The Atlantic LNG project currently under construction in Trinidad, scheduled for completion in 1999, is expected to market a large part of its output to Spain and to the Northeast United States.

In the United States, LNG accounts for a small portion of total gas consumption. This is not expected to change materially over the next decade, although some increases in quantity purchases are expected, especially once the Trinidad project comes online in 1999.

LNG Technology and Economics

Elements of LNG Projects

LNG projects comprise several distinct elements, each of which is necessary to implement a successful project:

- **A large, low-cost source of natural gas.** A successful LNG project must have sufficient proven reserves of natural gas to support liquefaction capacity for 15 to 20 years. To ensure adequate "deliverability" of gas even at the end of the project, reserves ought to be 25 to 35 times larger than the annual capacity of the plant. This means, for example, that a 500 million cubic foot per day project would require proven reserves of 5.4 to 7.6 trillion cubic feet.[27] In addition, production costs (including applicable production taxes levied by the host government) need to be low.

- **A liquefaction facility, including a jetty and loading facilities for LNG tankers.** Liquefaction facilities are large and expensive, typically costing several billion dollars. A typical set of facilities would include facilities for stripping natural gas liquids from the natural gas, processing and export of liquefied petroleum gas (LPG), the liquefaction facility itself, insulated pressurized LNG and LPG storage tanks with capacity sufficient to load the largest tanker expected to call, a jetty and LNG loading facilities with sheltered, deepwater access to

[23]"India Calls for LNG," *Alexander's Gas & Oil Connections: News and Trends*, web site www.gasandoil.com (December 8, 1996).
[24]"China/LNG: Shanghai Seeks LNG Funds," *Financial Times International Gas Report*, No. 320 (April 4, 1997), p. 29.
[25]British Petroleum Company, *BP Statistical Review of World Energy 1996* (London, UK, June 1996), p. 28, web site 165.121.20.76/bpstats.
[26]V. Thomas, "LNG Shifts Course for New Markets," *Financial Times International Gas Report*, No. 321, p. 33.
[27]The project needs sufficient gas to supply it for 15 to 20 years, with a terminal reserves-to-production ratio of 10 to 15, to ensure that the full contract amount can be produced at the end of the contract period. Arithmetically, if annual deliverability is 500 million cubic feet per day (0.1825 trillion cubic feet per year), then the amount needed is 25 to 35 x 0.1825 = 4.5 to 6.4 trillion cubic feet. If one accounts for "shrinkage" from extraction of natural gas liquids and nonhydrocarbon gases, as well as liquefaction plant and tanker fuel use, "wet gas" reserves need to be perhaps 20 percent larger than "dry gas" reserves, or 4.5 to 6.4 x 1.2 = 5.4 to 7.6 trillion cubic feet.

the ocean, and associated infrastructure, including roads, electric power, water, and employee housing.[28]

- **LNG Tankers.** Each project requires several dedicated LNG tankers, which are among the most complex and expensive merchant ships ever built, because of their double hulls and special lining. Each new 135,000 cubic meter (3 billion cubic foot) capacity tanker costs on the order of $260 million.[29] The number of tankers required for a project depends primarily on the distance between the liquefaction plant and the customer.[30] In general, transportation costs increase linearly with distance.

- **Regasification Plant.** LNG can be unloaded only in specialized terminals, which typically include a jetty and unloading facilities, LNG storage equal to at least a single tanker cargo, regasification facilities, and connections to pipelines to ship the gas to customers. The cost of regasification terminals varies with capacity, local construction costs, and the amount and type of site preparation costs, but would be unlikely to be less than several hundred million dollars.

The immense costs of each link in an LNG project impose their own logic. Projects can be undertaken only by large organizations with great financial capacity and a depth of project management skills. A typical customer would be a mid-sized natural gas distribution company with 50,000 to 100,000 customers. A successful project requires the cooperation of the host government (where the gas resources are located), the organization that owns the natural gas rights (private or state oil company), the government in the consuming country, consuming organizations (national or private electric utilities, gas companies, etc.), and a host of specialized organizations, such as shipyards, financiers, tanker operators, construction companies, process technology licensors, etc. Agreement must be reached *in advance* over the distribution of the large costs, the larger benefits, and the considerable risks associated with a project. Reaching these agreements will generally require protracted negotiations, as well as considerable upfront expense in risk-reducing feasibility and engineering design studies.

LNG Markets

Not every country is a potential market for LNG. In general, the following criteria need to be met:

- Domestic energy resources must be limited or expensive. Domestic gas production must be very low or declining, with little prospect of future increases. As a corollary, pipeline imports of natural gas must be impossible, or limited in potential quantity. Domestic coal production must be limited or costly.

- The domestic market for boiler fuel must be large and relatively concentrated—large enough, at a minimum, to absorb 250 to 500 million cubic feet per day of gas. If a large amount of new pipeline infrastructure is required to bring the gas to the consumers, the acceptable ceiling price for LNG may be correspondingly lower to justify construction of the infrastructure.

- Consumers may be willing to pay a premium for LNG if they believe it is important to reduce emissions of pollutants, particularly sulfur dioxide and carbon.

If these conditions are met, the consuming country is probably burning large volumes of petroleum for power and heating. Petroleum-based power generation usually takes the form of steam turbines burning residual oil for older plants, or newer (or prospective) gas turbine/combined-cycle plants burning gas oil.[31] Existing oil-fired plants can be retrofitted to burn natural gas without too much difficulty, with natural gas being approximately a Btu-for-Btu substitute for the oil. Figure 2 illustrates the evolution of fuel oil prices in European and Far Eastern spot markets.

As a boiler fuel, LNG approximates diesel fuel in product quality. It has negligible sulfur content and is suitable for use with low-cost, high-efficiency gas turbine and gas turbine/combined-cycle generating plants. Natural gas emits less carbon than either coal or oil. Figure 2 also shows heavy fuel oil prices actually paid

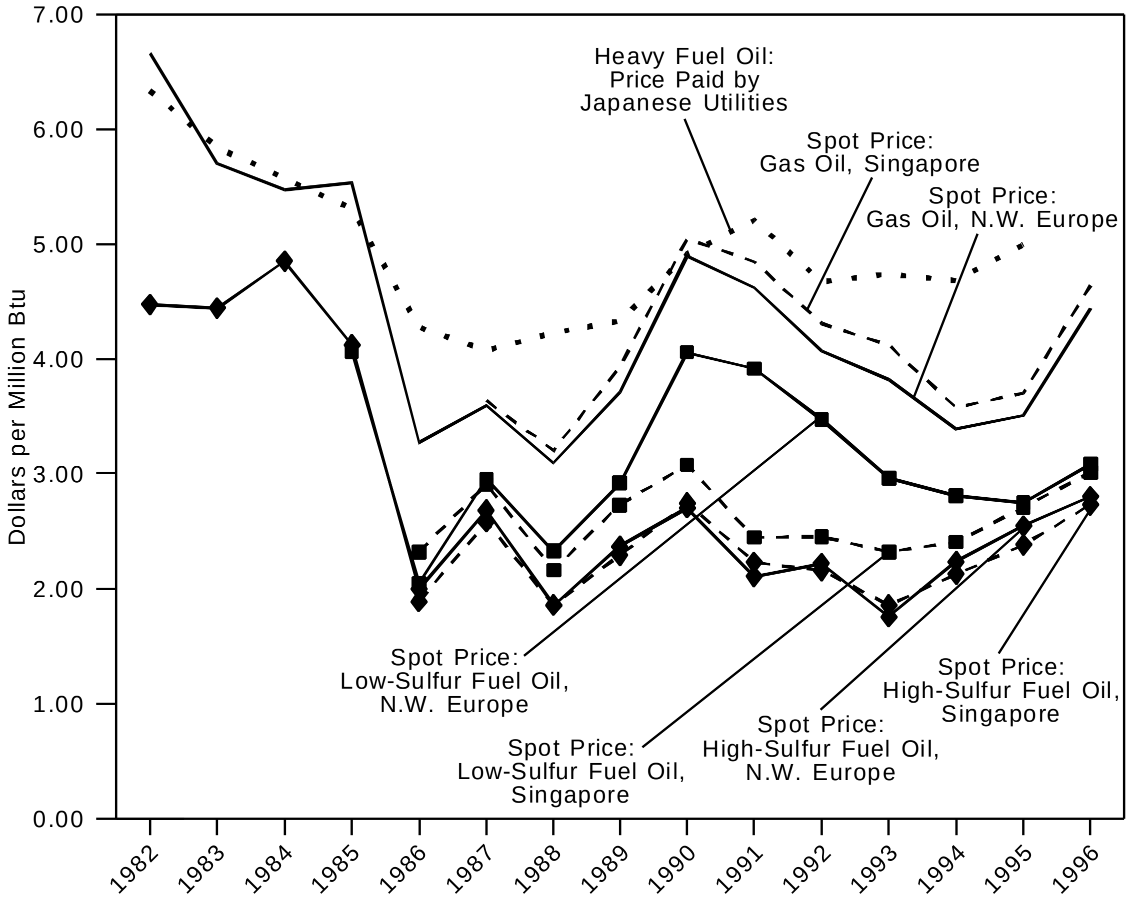
[28]Ideally, the plant would be located in a good natural harbor, on flat ground, remote from any centers of population, and close to the natural gas supply. To the extent that the actual site varies from the ideal, costs rise accordingly.

[29]T. Toichi, "LNG Development at a Turning Point and Policy Issues for Japan," *Energy in Japan*, No. 126 (March 1994).

[30]For example, a notional 4 million metric ton (534 million cubic feet per day) project would require delivery of 65 cargos of 3 billion cubic feet each year. LNG tankers are designed to travel at 20 knots: if the LNG plant is 3,000 nautical miles distant from the customer (say, Australia-Japan), a round trip by tanker would take (including time in port) about 17 days. Thus, a single tanker could deliver 21 cargos in a year, and three or more tankers would be required for the project. If the LNG plant were 7,000 nautical miles distant (say, Middle East-Japan), then a round trip would take 35 days, and 6 to 7 tankers would be required. This example abstracts from the problem of maintaining delivery schedules when tankers need periodic overhaul, or due to weather-related delays.

[31]"Gas oil" is a liquid petroleum distillate, often traded internationally, that would be described in the United States as a "middle distillate" and is generally comparable to No. 1 fuel oil, home heating oil, or diesel fuel.

Figure 2. Spot Prices for Petroleum Prices in Northwest Europe (Rotterdam) and Singapore, 1982-1996



Source: International Energy Agency, *Energy Prices and Taxes*, Fourth Quarter 1996 (Paris, France, 1997), pp. 5-6.

by Japanese electric utilities in recent years, at prices considerably above Singapore spot market rates.

Fuel for residential and commercial use is another premium-priced market, where natural gas might compete with expensive electricity, LPG, and heating oil (or polluting coal and fuelwood), and also provide environmental benefits. However, residential markets require careful analysis. Ideally (from the point of view of the potential supplier), there is an existing infrastructure to supply “town gas” (gas synthesized from coal) that natural gas can use, as was the case in Japan. If the gas transmission and distribution infrastructure must be built from scratch (as in Europe or Korea in recent years), the natural gas may need to be attractively priced to justify the construction cost of the infrastructure. Finally, in tropical countries where winter heating loads are negligible, residential gas demand may be insufficient to justify building infrastructure at any reasonable price.

If the middle distillate and residential fuels markets are too limited, LNG may need to compete for a larger market for existing steam turbine generators burning residual oil. This is a lower priced market, which, under current market conditions, tends to cap the price that consumers are willing to pay for LNG at $2.00 to $3.00 per million Btu. If the customer is indifferent to sulfur dioxide emissions and able to use high-sulfur fuel oil, the minimum acceptable price drops even further.

Thus, customers may seek to link prospective LNG prices to high-sulfur fuel oil, low-sulfur fuel oil, gas oil, or even imported coal, depending on their view of the development of their markets. Under current market conditions, however, it is difficult to negotiate prices that exceed gas oil parity (about $4.00 per million Btu under current market conditions) and progressively easier to negotiate prices below this level.

LNG Production Costs

No LNG project is likely to proceed unless the developers receive some assurance that they will be able to earn an acceptable return on their multibillion-dollar investments. A successful LNG project has a price that is low enough to motivate consumers to use large volumes of natural gas, backing out fuel alternatives, while still high enough to persuade developers and borrowers to actually build the project.

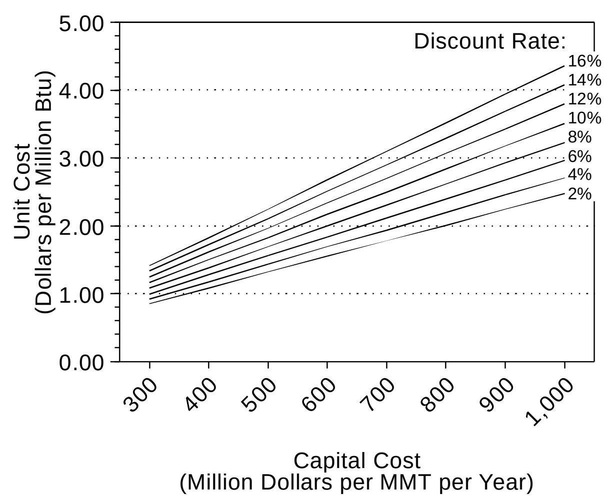
LNG developers will seek (but not always find) a long-term contract for their product at a price that is sufficient to cover their capital costs, which includes "take or pay" and "floor price" arrangements to ensure that the project can service its debts even in a lower-than-anticipated energy price environment.[32] It is also common for consumers to be offered or to take an equity stake in LNG projects, so as to encourage a community of interest between the buyer and the seller.

Natural gas production costs must be relatively low—typically, less than $1.00 per million Btu, and preferably on the order of $0.50 per million Btu. This implies that gas production must be from a relatively small number of wells that are capable of sustained high-volume production.[33] On the other hand, if natural gas production yields significant volumes of condensate or natural gas liquids, the revenues from petroleum coproduction may be sufficient to cover the cost of natural gas production, permitting the LNG project to benefit from low natural gas feedstock prices.

Extracting liquids and condensates, while usually profitable, exacts an arithmetic cost. Typically, 10 percent or so of gross gas production disappears into "shrinkage" in the form of extracted liquids and non-hydrocarbon gases. Thus, gross production (and gas reserves) must exceed the volume of gas delivered to the liquefaction plant by the amount of shrinkage.

Liquefaction plants are typically the most expensive element in an LNG project. As noted above, the cost will depend on a host of site-specific factors and on project scale, with larger projects having lower unit costs. As a rule of thumb, $300 to $900 million of capital cost for each 1 million metric tons per year (about 133 million cubic feet per day) of capacity seems to be typical of current projects.[34] How this capital cost gets distributed over the life of an LNG project will depend on a host of financing details and inflation assumptions, but principally on the developer's target rate of return on capital. As an illustration of this point, Figure 3 shows calculated unit costs of liquefaction for a notional 1 million metric ton liquefaction facility as a function of the discount rate and project cost. Figure 3 indicates that a set of typical acceptable prices for regasification facilities might be in the range of $2.00 to $3.00 per million Btu, although excessive capital costs or high target rates of return could kill any project.

Figure 3. Sensitivity of Liquefaction Unit Costs to Capital Costs and Discount Rates



MMT = million metric tons of capacity.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Calculated on the basis of a 30-year amortizing loan and operating costs of $0.15 per million Btu processed plus 7.5 percent of capital cost annually.

[32]For instance, a recent account in the trade press of negotiations between Korean buyers and Omani sellers indicated that the Omanis were seeking a floor price of $2.25 per million Btu, with the LNG normally sold at 90 percent of the average cost of LNG imported into Japan. Japanese LNG import prices are, in turn, linked to crude oil import prices. "Oman LNG Finally Locks Up a Stubborn South Korea," *World Gas Intelligence* (March 15, 1996), p. 1.

[33]The U.S. Department of Energy's Office of Policy commissioned a study of the resource cost of undeveloped nonassociated gas reserves in 32 countries around the world. The study concluded that there were 665 trillion cubic feet of gas which could be developed at a resource cost of less than $1.00 per thousand cubic feet. See: U.S. Department of Energy, Office of Domestic and International Energy Policy, *Assessment of Costs and Benefits of Flexible and Alternative Fuel Use in the U.S. Transportation Sector: Technical Report Nine: Development Costs of Undeveloped Nonassociated Gas Reserves in Selected Countries* (Washington, DC, January 1993), p. xiv.

[34]See table in T. Toichi, "LNG Development at a Turning Point and Policy Issues for Japan," *Energy in Japan*, No. 126 (March 1994). A U.S. Department of Energy study estimated capital costs for a liquefaction plant, gas pretreatment, storage, and marine facilities at $1.7 to $2.1 billion 1987 dollars (depending on the availability of existing infrastructure) for a nominal 6.4-million-ton-per-year (1 billion cubic feet per day) plant, or $264 to $325 million per million tons of capacity. See: U.S. Department of Energy, Office of Policy, Planning, and Analysis, *Assessment of Costs and Benefits of Flexible and Alternative Fuel Use in the U.S. Transportation Sector: Technical Report Three: Methanol Production and Transportation Costs* (Washington, DC, November 1989), p. 33.

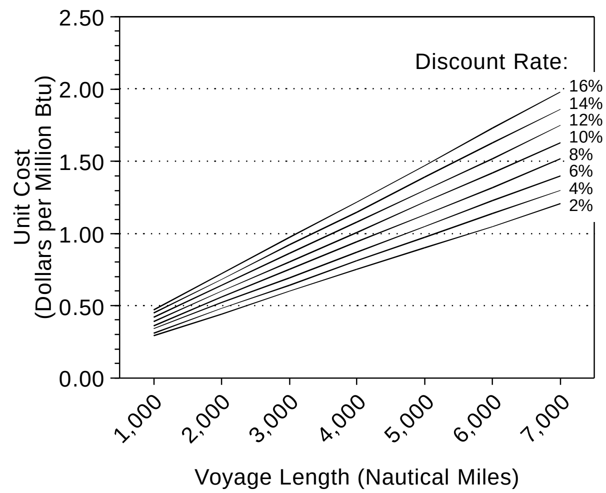
Operating costs are relatively minor. Liquefaction is a very energy-intensive process. Typically, about 8 to 9 percent of the natural gas delivered to an LNG plant is used as plant fuel to liquefy the rest.[35] However, as noted above, the cost of the natural gas delivered to the liquefaction plant is inherently very low.

LNG tankers are complex and expensive ships, typically costing $260 million for each 135,000 cubic meter capacity vessel.[36] The number of tankers required is a function of the distance between the export terminal and the import terminal. The unit cost of marine transport is primarily a function of the capital cost of the tanker, the financing terms and acceptable rate of return for the tanker owners, and the distance to be covered. Other less important issues include the cost of bunker fuels for the tanker and the cost of arrangements for spare transport capacity when dedicated tankers are being refitted.

Finally, the tanker's LNG cargo is cooled by evaporating a fraction of the cargo ("boiloff") and burning the evaporated fraction as boiler fuel. Typically, about 0.15 to 0.25 percent of the cargo is consumed per day, during which the tanker will travel about 480 nautical miles.[37] Thus, moving LNG from the Persian Gulf to Japan (about 7,000 nautical miles) will consume 3.6 percent of the cargo. Figure 4 illustrates how transport costs might vary as a function of distance and discount rate chosen.

Regasification plant costs are typically considerably lower than liquefaction plant costs. At present, there are regasification plants in most major consuming markets. However, opening up new LNG markets in new countries (for example, China or the Philippines) would require a considerable initial infrastructure investment that consumers would expect to recoup from savings on energy costs or via emissions benefits. A U.S. Department of Energy study estimated the capital cost of a new regasification plant at $700 million (1988 dollars) for a 500-million-cubic-foot-per-day facility, equivalent to $0.56 per thousand cubic feet.[38] Regasification energy requirements will also consume a further 2.5 percent of the delivered natural gas. However, the marginal cost of using an existing regasification

Figure 4. Sensitivity of LNG Transport Costs to Voyage Lengths and Discount Rates



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Calculated on the basis of a 30-year amortizing loan; service with tankers with capacity of 135,000 cubic meters of LNG, each costing $260 million, speed 19.5 knots, 1.7-day port turnaround, in service 340 days per year, and fuel price $24 per barrel; and operating costs of about 10 percent of capital cost annually. Does not take into account requirements for spare tankers or scheduling issues.

plant with excess capacity, or expanding the capacity of an existing plant, would be far lower than the cost of building a new "greenfield" facility.

From the above review, it is clear that LNG project costs can vary considerably, particularly with respect to the effects of local construction costs. As a summary estimate, however, a successful LNG project might have production costs of $0.50 per million Btu, liquefaction costs of $2.50 per million Btu, and transport costs of $0.75 per million Btu, for a typical project cost of perhaps $3.75 per million Btu delivered to the regasification plant.

Two years ago, the Institute for Energy Economics of Japan prepared a review of project costs (as reported in the trade press) for various prospective LNG projects, and calculated pro forma supply costs at various discount rates. Their review is summarized in Table 2.

[35]M.A. Adelman and M. Lynch, "Natural Gas Supply in the Asia-Pacific Basin," in Massachusetts Institute of Technology Center for Energy Policy Research, *East Asia/Pacific Natural Gas Trade: Final Report*, 86-006 (Cambridge, MA, March 1986).

[36]T. Toichi, "LNG Development at a Turning Point and Policy Issues for Japan," *Energy in Japan* No. 126 (March 1994).

[37]M.A. Adelman and M. Lynch, "Natural Gas Supply in the Asia-Pacific Basin," in Massachusetts Institute of Technology Center for Energy Policy Research, *East Asia/Pacific Natural Gas Trade: Final Report*, 86-006 (Cambridge, MA, March 1986).

[38]U.S. Department of Energy, Office of Policy, Planning, and Analysis, *Assessment of Costs and Benefits of Flexible and Alternative Fuel Use in the U.S. Transportation Sector: Technical Report Twelve: Economic Analysis of Alternative Uses for Alaskan North Slope Gas* (Washington, DC, December 1993), p. 27.

Table 2. Estimated Costs for Selected New LNG Projects

Project	Output (Million Metric Tons per Year)	Estimated Total Investment (Billion Dollars)	LNG Supply Cost (Dollars per Million Btu)	
			Discount Rate 15 percent	Discount Rate 12 percent
Qatar Gas	4	4.0 - 4.5	4.05 - 4.44	3.55 - 3.87
Oman	5	5 - 6	4.06 - 4.69	3.56 - 4.08
Indonesia Natuna	14	20 - 25	4.99 - 6.10	4.27 - 5.20
Malaysia LNG-3	5	4.5 - 5.0	3.40 - 3.71	2.94 - 3.20
Papua New Guinea Onshore	6	8.0 - 8.5	4.81 - 5.07	4.14 - 4.35
Australia Bonaparte	2	2.5	4.59	3.95
Australia Gorgon	6	7 - 8	4.29 - 4.81	3.70 - 4.14
Sakhalin	6	7.5 - 8.5	4.38 - 4.89	3.81 - 4.24

Note: This analysis assumes a 20-year project life. Both tanker and production costs are included.

Source: T. Toichi, "LNG Development at a Turning Point and Policy Issues for Japan," *Energy in Japan*, No. 126 (March 1994).

The analysis above may use higher discount rates than developers are using, and it may not completely account for coproduction of LPG and condensates in project revenues. Nevertheless, it offers an interesting window into the relative costs of different prospective LNG projects. It is also notable that the actual delivered cost of LNG to Japan under a mix of spot and long-term contract arrangements to Japan is typically $3.00 to $4.00 per million Btu.[39]

Recent Developments in LNG Markets

Several interesting market developments in the LNG business have created a modest boom in LNG operations, improving the prospects for future growth. LNG projects, as noted above, have generally been based on a firm supply contract between buyer and seller, in which the buyer is required to "take or pay," while the seller is required to "deliver or pay." LNG projects are thus designed to deliver the contractual amount of gas with a high degree of reliability. In practice, this has meant designing in excess capacity, so that excess liquefaction capacity is available most of the time, and "spare" tankers are available to cover scheduled overhauls. The cost of this excess capacity is embedded in the project's main contracts. Consequently, many LNG producers have volumes of LNG available in excess of contract volumes, for which the marginal cost of production and transportation is a fraction of the full cost of the main contract volumes. Producers have proven willing to sell these volumes on a developing "spot" market at competitive prices.

Spot trading in LNG—grown from almost nothing in 1992—currently accounts for around 3 percent of the total market.[40] In the United States, the Boston-based Cabot Corporation has signed an agreement with Australia's Northwest Shelf LNG project to purchase three cargoes of LNG on a spot sales basis. The first shipment of 125,000 cubic meters (2.75 billion cubic feet) was scheduled to reach Cabot by mid-1997.[41] In an attempt to enter the European LNG market, Qatar's Qatargas LNG project plans to sell spot cargos to Europe beginning in September 1997.[42]

The development of the LNG spot market has also been stimulated by other events. Contract disputes between buyers and sellers have made LNG from existing plants unexpectedly available. Further, some LNG projects are now old enough so that their original 20-year supply contracts have expired. The owners of these projects have considerably more pricing flexibility than owners of prospective future projects. Projects that have collapsed have produced a flock of uncommitted LNG tankers available for spot charter or sale at a fraction of construction cost. As of 1993 (the point at which the LNG spot market began to expand rapidly), one source estimated that some 9 large LNG tankers (14 percent of the worldwide fleet) were idle.[43]

[39]"Asian LNG Prices," *World Gas Intelligence* (January 15, 1997), p. 10.
[40]V. Thomas, "LNG Shifts Course for New Markets," *Financial Times International Gas Report*, No. 321, p. 33.
[41]"US Takes First Aussie LNG," *Financial Times International Gas Report*, No. 321 (April 18, 1997), p. 26.
[42]"Qatargas to sell to Europe," *Financial Times International Gas Report*, No. 320 (April 4, 1997), p. 26.
[43]C. Lyons, "Gas Deal Up for Re-negotiation," *Seatrade World Review Monthly* (July 1994), p. 25.

Finally, the cost of adding incremental capacity to existing plants is often considerably lower than building a new plant. This has paved the way for the expansion of the market through lower cost "capacity creep." The Institute for Energy Economics of Japan estimates that typical capacity for existing LNG plants may be as much as 25 percent in excess of rated "nameplate" capacity.[44] In the United States, the Everett, Massachusetts, regasification plant operates at 30 billion cubic feet of its full capacity of 92 billion cubic feet. By 1999, the facility is expected to reach full capacity, potentially expanding to 140 billion cubic feet by 2005. Expansion at the Lake Charles, Louisiana, facility is also possible; and the Cove Point, Maryland, and Elba Island, Georgia, facilities could also be reopened under the right economic circumstances.

The development of the LNG spot market has also led to an apparent relaxation of the constraints on new project development. Rather than nailing down project volumes through a set of long-term contracts, operators in the 1990s have proven willing to go ahead with projects even in the absence of long-term contracts for the full volume, in the faith that contracts will ultimately materialize, or, at worst, that a portion of the product can be sold (perhaps at a discounted price) on the spot market. Thus, the development of an LNG spot market has apparently reduced the risk inherent in new LNG projects.

The Future of Liquefied Natural Gas

LNG holds considerable potential for future natural gas trade, which can be unlocked in several different ways:

- Countries such as Thailand, Brazil, the Philippines, China, and India may elect to build regasification facilities in the future.
- LNG capital costs may continue to decline with improving technology. The minimum efficient scale for LNG projects may decline, creating opportunities for smaller export projects.
- The development of an active spot market with more exporters and importers may improve utilization rates on expensive fixed liquefaction and transport capacity, as well as reducing project risk.
- Markets for premium-priced "clean" fuels may expand in current and potential consuming countries with increasing wealth and increasing public concern about air quality or greenhouse gas emissions.
- LNG use to cover peak consumption periods and to enhance gas system reliability may grow.

LNG projects, however, are not created in a vacuum. They must compete with other fuels and even with other gas export technologies. As noted in the previous section, today LNG projects compete against coal and petroleum products in power generation markets and, potentially, against "town gas," middle distillates, and liquefied petroleum gas in smaller premium residential markets.

There are several alternative technologies for moving natural gas from places where it is plentiful to places where it is scarce, and owners of gas reserves may elect to adopt one of these alternatives. Among the more common:

- **Ammonia/urea manufacture.** Ammonia is a common industrial chemical; however, its most important use is in the manufacture of urea, the principal building block in nitrogen fertilizers. Most new export-oriented plants integrate ammonia and urea manufacture, using natural gas as a feedstock. In common with other natural gas technologies, ammonia plants are very capital-intensive; however, a world-scale ammonia/urea plant (1,000 tons of ammonia per day, 1,700 tons of urea per day) uses only 35 million cubic feet of natural gas per day. Most states with significant gas reserves have export-oriented ammonia plants and could build more. The economics of ammonia plants are only moderately affected by feedstock costs. The world fertilizer market is very complex, riddled with producer and consumer subsidies and other market distortions.

- **Methanol.** Methanol is a common industrial chemical feedstock, and it can also be used as an alternative liquid transportation fuel.[45] Methanol is usually manufactured from natural gas. Methanol plants tend to have much higher capital costs per Btu than do LNG liquefaction plants, but lower

[44]T. Toichi, "LNG Development at a Turning Point and Policy Issues for Japan," *Energy in Japan*, No. 126 (March 1994).

[45]High prices limit the use of methanol to high-value markets as a chemical feedstock or a substitute for gasoline. The United States consumed about 370 gasoline-equivalent barrels of methanol per day as a liquid transportation fuel in 1995. See Energy Information Administration, *Alternatives to Traditional Transportation Fuels 1995*, DOE/EIA-0585(95) (Washington, DC, December 1996), p. 20. Domestic production of methanol (primarily for feedstock use) in 1994 was 5.5 million metric tons (120,000 barrels per day). See U.S. International Trade Commission, *Synthetic Organic Chemicals, United States Production and Sales, 1994*, USITC Publication 2933 (Washington, DC, November 1995), p. 3-27. Current imports appear to be about 2 million metric tons, and current spot prices are $26.50 per barrel ($9 per million Btu). See web site www.bonnermoore.com.

transportation costs.[46] However, the two factors approach balance only at very great transportation distances (for example, from the Persian Gulf to New York), where the cost of both fuels is significantly higher than recent petroleum products prices. World-scale methanol plants (2,500 metric tons per day) consume only 75 to 90 million cubic feet of natural gas per day and produce the energy equivalent of 48 million cubic feet of methane per day. Most gas-exporting countries have already built at least one methanol plant. Absent higher oil prices or legal requirements for alternative transportation fuels, the methanol market will remain a relatively small chemical-oriented market, rather than a large fuel-oriented market.

- **Methyl tertiary butyl ether (MTBE).** The decision to adopt reformulated gasoline in "nonattainment" areas in the United States frequently has been implemented by blending gasoline with MTBE, an oxygenate additive that reduces engine knocking. This has created a large market for MTBE in the United States. Because MTBE is made, in part, from methanol, it has also expanded the methanol market.[47] Imported MTBE competes with domestically produced MTBE: while the foreigners have lower feedstock costs, their product has higher transport costs. MTBE is also sometimes used in lesser proportions as an "octane enhancer" in unleaded "conventional" gasoline.

  MTBE is relatively simple to make: almost all of the cost is in the methanol and petroleum-based feedstocks.[48] If other countries follow the U.S. practice of converting first to unleaded gasoline and subsequently to reformulated gasoline, MTBE markets will expand accordingly; however, even a very large expansion of MTBE markets will not require enormous increases in natural gas usage.

- **Synthesis of petroleum products.** It is technically feasible to synthesize almost any hydrocarbon from any other. Industrial processes have been developed to synthesize valuable liquid hydrocarbons from inexpensive natural gas. The two most popular methods have been the "Fischer-Tropsch" process (first used by the Germans to make synfuels from coal during World War II) and methanol-based processes. Mobil developed the "M-gasoline" process to make gasoline from methanol, which was implemented about 15 years ago in a large integrated methanol-to-gasoline plant in New Zealand. The New Zealand plant was a technical success but a commercial failure, producing gasoline at costs above $30 per barrel, and requiring large subsidies from the New Zealand government. More recently, Exxon has developed a new chemical method, based on the Fischer-Tropsch process, to synthesize diesel fuel from natural gas. Exxon says that better catalysts and improved oxygen-extraction technologies have greatly reduced the capital cost of the process, and that it is actively marketing the process internationally.[49]

  Another synfuel technology vendor is Sasol. Sasol was established to provide apartheid-era petroleum products in coal-rich but oil-poor South Africa. The firm built a series of Fischer-Tropsch coal-to-oil plants, and is probably the world's most experienced synthetic fuels organization. Sasol is now marketing a natural-gas-to-oil technology. Sasol has formed a "strategic alliance" with Statoil, the Norwegian national oil company, to construct barge-mounted gas-to-oil plants that can be floated into place over small natural gas deposits. Sasol claims that its process can produce middle distillates at a capital cost of $30,000 per daily barrel, with operating costs of $5.00 per barrel (excluding

[46]A 2,500-metric-ton-per-day plant costs $240 to $350 million in 1988 dollars. Some 32 to 44 percent of the energy input is consumed in making the methanol. Thus, about three such plants would be required to deliver the same energy as a 1-million-ton-per-year LNG train. Methanol is typically transported in specialized chemical products tankers, but it could be cheaply transported in bulk in slightly modified petroleum products tankers. See U.S. Department of Energy, Office of Domestic and International Energy Policy, *Assessment of Costs and Benefits of Flexible and Alternative Fuel Use in the U.S. Transportation Sector: Technical Report Three: Methanol Production and Transportation Costs* (Washington, DC, November 1989).

[47]About 1 gallon of methanol is needed for each 3 gallons of MTBE. U.S. refiners produced 169,000 barrels of MTBE per day and imported 46,000 barrels per day in 1996. This is about 3 percent of U.S. gasoline consumption. See Energy Information Administration, *Petroleum Supply Annual 1995,* DOE/EIA-0109(95/2) (Washington, DC, June 1996), pp. 71 and 132. Current U.S. Gulf spot MTBE prices are $35 per barrel, compared with about $26 per barrel for wholesale unleaded regular gasoline. See web site www.bonnermoore.com.

[48]A 2,400 barrel per day MTBE plant was estimated to cost only $5.5 million in 1988 dollars. Pace Petrochemical Service, *Annual Issue* (September 1989), pp. 188-189.

[49]"Gas to Oil: A Gusher for the Millennium," *Business Week* (May 19, 1997). This article suggests that the cost of synthetic diesel fuel would be on the order of $20 per barrel and "perhaps as low as $15 per barrel." The article goes on to say that Exxon is negotiating to build a $1.2 billion plant with "an initial capacity on the upside of than 50,000 barrels a day" in Qatar. Qatari government officials, in a recent meeting with their U.S. Department of Energy counterparts, said that the costs proposed to them were considerably higher than those described in this article.

feedstock costs) and a thermal efficiency of 60 percent.[50]

The Syntroleum Corporation (of Tulsa, Oklahoma) is also marketing an alternative natural-gas-to-diesel technology. The company says that its process has a capital cost of $12,000 to $14,000 per daily barrel of diesel for a 20,000 to 25,000 barrel per day facility, and operating costs of $3.50 to $5.64 per barrel.[51] The thermal efficiency of the Syntroleum process is reportedly about 60 percent, implying a requirement for about 90 million cubic feet per day of dry gas for a $300 to $350 million, 25,000 barrel per day capacity facility. These figures (if achievable in practice) are consistent with a unit cost of less than $20 per barrel ($3.40 per million Btu) of diesel fuel, and the required economic scale appears to be smaller than that for LNG.

Petroleum products are far easier to transport and market than is LNG. They can be moved in existing pipelines or products tankers and even blended with existing crude oil or product streams if necessary. No special contractual arrangements are required to sell them, and there numerous suitable domestic and foreign markets. The key to the economics are the capital and operating costs of the plant, feedstock costs, and, secondarily, the ability of the operator to achieve high utilization rates. Owners of natural gas reserves will naturally be interested in whether LNG or gas-to-oil plants yield the largest return on investment. Where there are both underused oil reserves and large undeveloped gas reserves, as in Saudi Arabia, Iran, and Abu Dhabi, governments would find the profitability of increasing conventional oil production far superior to any gas-to-oil technology.

- **International pipelines.** Gas pipelines are probably the least expensive and most effective means of moving bulk energy over long distances that the human race has yet devised. International pipeline projects hold the promise of moving natural gas from places where it is plentiful (e.g., the Persian Gulf) to places where it is scarce (e.g., the Indian subcontinent). However, there are preconditions to successful implementation of an international pipeline project, which can be difficult to achieve:
  - First, the governments along the route must be seen to be sufficiently stable and "law abiding" to make commitments that will be binding upon successor governments. Once a pipeline is built, upstream governments can impose large economic costs on downstream governments by imposing new tariffs or shutting down the pipeline. Downstream governments must be confident that this will not occur.
  - Universal agreement must be reached among pipeline operators, consumers, intermediary states (if any), and resource owners on the distribution of costs and benefits from the project. Unreasonable behavior on the part of any party will prevent the project from going forward.
  - There must be a large downstream gas market. As in the case of LNG projects, long-distance pipeline projects require large volumes to be economical. The U.S.-Canadian border is criss-crossed with pipelines. Europe has also developed an effective international gas transmission system. In South America, political and economic reform has had the side-effect of also making interstate pipeline projects possible. On the other hand, a large-diameter pipeline running from Iran to Pakistan and on to India would probably be eminently feasible technically and economically but is politically impossible at present. There are many other such potential projects.
- **Deepwater pipelines.** Pipelines have been successfully laid under the ocean and through mountains, swamps, tundra, and permafrost. However, the difficulty and expense of laying (and repairing) pipelines beneath the ocean increases enormously with water depth. No one has ever attempted to lay pipelines in water more than a few hundred feet deep. The construction of large-diameter pipelines across the Mediterranean, connecting Algeria with Spain and Italy, has had a significant dampening effect on trans-Mediterranean LNG markets, and the development of similar projects in Asia would have a similar effect. In recent years, the Oman Oil Company (mostly owned by the government of the Sultanate of Oman) has proposed a pioneering deepwater pipeline to connect Oman and India. This project is clearly an alternative to a Middle East-India LNG project, and it bypasses the technically easy but politically insoluble problem of building an onshore or shallow-water pipeline via Iran and Pakistan. However, it has never been made clear who would be able to build the deepwater pipeline, nor how much it would cost. In the future, if the technical and economic hurdles can be overcome, there are many areas where deepwater pipelines could be effective competitors to future LNG projects.

[50]Sasol describes its strategic alliance with Statoil and its process technology on its web site, www.sasol.co.za.
[51]M.A. Agee, "Convert Natural Gas into Clean Transportation Fuels," *Hart's Fuel Technology & Management* (March 1997), pp. 69-72.

The market for LNG may also be ultimately be affected by the Framework Convention on Climate Change signed in 1992, and its successor agreement, now being negotiated. Governments wishing to limit national emissions of greenhouse gases may look with favor on natural-gas-fired high-efficiency power generation equipment. It should be noted, however, that while burning natural gas emits less carbon dioxide than any other fossil fuel, the process of liquefying, transporting, and regasifying LNG is very energy intensive, and the fuel consumption associated with the supply chain increases the "fuel cycle" emissions factor for LNG by about 15 percent. LNG still has lower emissions per unit of energy consumed than do petroleum fuels. On the other hand, methanol (and, by extension, MTBE) would have even higher emissions than petroleum if the energy consumption from making the methanol were counted. Pipeline systems are generally very energy-efficient: only a few percent (at worst) of the gas flowing through a pipeline system is needed for fuel. However, none of these "fuel cycle" emissions consequences may matter if the consuming country is a participant in the agreement and the exporter does not participate.

Conclusions

LNG costs may fall, and the market for premium-priced "clean" fuels may expand. However, for LNG to gain market share rapidly, crude oil prices must remain above $20 per barrel. The most striking feature of all the international gas transport technologies, taken as a group, is that they are all likely to be very attractive substitutes for conventional petroleum products (rather than specialized niche market players) at prices only moderately higher than current oil prices. Thus, these technologies can perform the function of "backstop" technologies over the next two decades. They can limit the long-run practicability of oil prices higher than $25 to $30 per barrel and / or coal prices higher than $40 per ton, and thus further constrain both the options of major oil producers and the long-run consequences of oil supply disruptions.

The Impact of International Learning on Technology Cost

by
Thomas W. Petersik

In its National Energy Modeling System (NEMS), the Energy Information Administration (EIA) assumes that the capital cost for a new electricity generating technology decreases as cumulative U.S. capacity increases. For the Annual Energy Outlook 1997 (AEO97)*, costs decrease 10 percent for every doubling of domestic capacity, until five units (plants) are built. However, evidence indicates that experience outside the United States (international learning) also lowers U.S. costs. Where equipment vendors, architect-builders, and owners and operators for new international units also compete in the United States, EIA posits that their international experience also lowers U.S. costs. For the* Annual Energy Outlook 1998 *(*AEO98*), EIA will credit new capacity outside the United States toward lowering U.S. capital costs of new generating technologies. This paper describes current EIA plans as of June 1997; however, both the overall NEMS learning function and its international component may change as a result of experience during preparation of* AEO98.

Introduction

Determining future capital costs for new electricity generating technologies is a critical step in preparing EIA's *Annual Energy Outlook* (*AEO*). Capital costs affect which technologies the Nation will choose—coal, natural gas, or renewables, for example—and are a component of the electricity prices future consumers will pay.

Experience in many industries, including electric power, shows that capital costs for new technologies decline as additional units enter service. Declines reflect efficiencies gained through experience by manufacturers, installers, purchasers, and users of the new technologies, because of economies of scale, technology evolution, and other factors. As used here, EIA refers to the full range of forces yielding cost declines as "learning."

EIA's National Energy Modeling System (NEMS) incorporates learning in the determination of capital costs for future generating technologies. However, the current learning function in NEMS (the algorithm for lowering capital costs) accounts only for cumulative U.S. capacity installed or projected to be installed in the United States. Projections are unaffected by experience with new technologies outside U.S. borders. In effect, NEMS assumes that international learning effects are zero.

This paper addresses the expansion of the NEMS domestic learning function to include international learning. Generating technology markets are global, and new technologies are being installed outside the United States, sometimes more often than domestically. Moreover, the installations frequently involve equipment produced by U.S. firms, designed or constructed by U.S. firms, or even owned or operated by U.S. firms. Where the equipment or personnel are not from the United States, the foreign firms actively compete in U.S. markets.

The paper has four parts. First, it summarizes EIA's current learning function. Second, it outlines the current literature and empirical evidence on international learning. Third, it describes EIA's introduction of international learning in this year's *AEO*. Finally, it identifies unresolved issues.

Current NEMS Learning Function

Based on the current literature, the NEMS learning function used in *AEO97* reduces the capital costs of new generating technologies by 10 percent with every doubling of cumulative capacity, through the fifth unit of commercial size.[1] In effect, capital costs drop by about 22 percent through the fifth unit, measured in terms of total domestic megawatts installed.

In the NEMS Electricity Market Module (EMM), learning implicitly incorporates

- Learning by doing (i.e., experience or pure classical "learning")
- Network externalities (growing availability of related products)
- Market efficiencies (competition)
- Scale economies in production (increased numbers or size)
- Technological interrelatedness (growth of technology subspecialties).

The function follows the general classical learning form as the slope of the logarithm of unit cost and the logarithm of cumulative production, in the log-linear form:

$$C_n = C_1 n^b \quad ,$$

where:

C_n = cost of the nth unit
C_1 = cost of the 1st unit
n = the number of the unit being estimated
b = exponent, natural log of the improvement-curve slope divided by the log of 2.[2]

In current NEMS applications,

C_1 = cost of the "first" commercial unit, where unit size is expressed as a defined quantity of capacity. For example, the "first" wind plant is represented by the first 50 megawatts of "new" wind technology on line, not the first actual plant.[3]

n = the fifth unit of the defined size for the technology. With the defined size of 50 megawatts, n is reached at 250 megawatts.

b = exponent, such that each doubling of cumulative capacity decreases the capital cost by 10 percent.[4]

Evidence of International Learning

The subject of international learning is not directly addressed in the literature. Neither the design of analyses nor the data sets used in them make any overt reference to borders or distinctions in learning based upon them. Indirect evidence in the literature is ambiguous and subject to interpretation. Further, almost all studies are restricted to experiences within one country; this restriction could be interpreted as limiting learning to a nation's borders.

The literature may also, however, implicitly reflect acceptance of learning across borders. Studies of learning in the synthetic fuels industry cross borders, beginning with the SASOL (I, II, III) plants in South Africa and extending to Canadian tar sands and the U.S. synthetic fuels experiments. Hess, in describing transfer of project-specific information, observes that personnel from SASOL also worked on the U.S. Great Plains project.[5] In addition, Hess also refers to a 1978 Charles River Associates study analyzing nearly 80 mines, mill-concentrators, and smelters built worldwide between 1965 and 1968, in which no country-by-country distinctions were made.[6]

The literature suggests that four broad underlying factors contribute to learning—presumably, across borders as well as within them. The key underlying factors are:

- **Learning Conveyed Via Technology (the Equipment).** First, U.S. learning occurs in manufacturing, regardless of the country of installation. Economies of scale, network externalities (increases in related products), and manufacturers' learning by doing (experience) affect every successive unit of manufacture. When U.S. firms manufacture generating

[1]For more detailed background on technology penetration and EIA's current learning function, see Energy Information Administration, *NEMS Component Design Report: Modeling Technology Penetration* (Washington, DC, June 1994) (unpublished draft report).

[2]For an overview of learning, see E.W. Merrow, *An Analysis of Cost Improvement in Chemical Process Technologies,* prepared for the U.S. Department of Energy (Santa Monica, CA: RAND Corporation, May 1989), p. 5.

[3]Learning could also be expressed as a function of the number of units rather than cumulative megawatts of capacity. However, because first units are often too small to convey the full learning effects of full-scale units, EIA uses cumulative capacity to avoid overstating the early units' learning effects.

[4]EIA's review of the literature notes overall learning ranges from 7 to 12 percent for each doubling of capacity. See Energy Information Administration, *NEMS Component Design Report: Modeling Technology Penetration* (Washington, DC, June 1994) (unpublished draft report).

[5]R.W. Hess, *Review of Cost Improvement Literature with Emphasis on Synthetic Fuel Facilities and the Petroleum and Chemical Process Industries,* prepared for the U.S. Synthetic Fuels Corporation (Santa Monica, CA: RAND Corporation, March, 1985), p. viii.

[6]R.W. Hess, *Review of Cost Improvement Literature with Emphasis on Synthetic Fuel Facilities and the Petroleum and Chemical Process Industries,* prepared for the U.S. Synthetic Fuels Corporation (Santa Monica, CA: RAND Corporation, March, 1985), p. 52, quoting Charles River Associates, *Startup of New Mine, Mill-Concentrator and Processing Plants for Copper, Lead, Zinc, and Nickel: Survey and Analysis* (Boston 1979).

equipment, the U.S. market enjoys learning effects. Further, the manufacturing need not occur domestically for U.S. learning to occur. If units installed in the United States result from foreign manufacturing, the domestic installation benefits from whatever learning the foreign manufacturer experienced. Finally, neither manufacture nor installation need occur domestically for the United States to receive some learning benefits. Learning will be transmitted via competitors. If a firm does not compete in U.S. markets but competes overseas, then its competitors active in the United States will adopt its advances or substitute others, thereby conveying some learning to the U.S. market. In sum, if equipment installed in the United States is the product of a competitive manufacturing market, learning effects will occur in the United States.

- **Learning Conveyed Via Information (People and Communication):** Learning travels via people and in the communication networks of firms. Their learning travels with them throughout the market. Consequently, where firms and people operate in the global market, their learning is global. However, a hierarchy in degree of learning emerges. Most important is hands-on familiarity with earlier sites; therefore, owner-operator experience is the most valuable. Second in importance is project designer and builder experience. Third is experience by licensors, architects and engineers, and equipment vendors. Finally, some successful learning is obtained from records and reports of indirect participants, including reports, journals, and conference records of participants and government and other third-party observer reports. Diffusion theory also supports the concept of international learning via people. Innovations diffuse through the example of those whose experience and knowledge are seen as relevant. Similarities in goals, education, attitudes, values, professions, and social status all support the communication of innovation and improvement across cultural and geographic barriers.[7]

- **Learning Conveyed by the Marketplace.** Evidence also suggests that learning accelerates when the marketplace is more competitive.[8] Where competition is keen, the values of learning and its successful application are enhanced. Where markets are closed—as might occur in non-market economies—innovation, learning, and its communication are slowed.

- **Learning Conveyed by Time.** Limited evidence suggests that the time interval between plants is significant for learning.[9] Ideally, sufficient time between units should pass to allow the experience from the first to be incorporated in the design of the second, and so on. Research on synfuels plants, for example, suggests that 5 to 10 years between plants may be needed to afford complete integration of learning between units. On the other hand, time intervals between units may also be too long, resulting in loss of experience and the breakdown of supporting markets.

Empirical evidence suggests that international learning occurs in U.S. electricity generating markets, conveyed both through technology and through people. First, electricity generating equipment markets are clearly global:

- The major producers of turbines used in fossil- and biomass-fueled plants—General Electric (GE), Westinghouse, ABB, and Siemens—all design, build, market, and deliver fundamentally identical products to customers around the world. A list of recent GE integrated gasification combined-cycle projects, for example, includes plants in Germany, the Netherlands, Italy, and the United States. Texaco projects include locations in China and Italy, as well as in the United States.[10]

- Vestas Wind Systems A / S, the leading Danish wind turbine manufacturer, has wind turbines installed in more than 25 countries and competes globally, including in the United States. Vestas wind turbines are built in factories in Denmark, Germany, India, and Spain, all to the same international (ISO9001) standards. The global market for Vestas turbines affords economies of scale among world wind turbine markets, including in the United States.[11]

[7]E.M. Rogers and F.F. Shoemaker, *Communication of Innovations, A Cross-Cultural Approach,* Second Edition (London, UK: Collier MacMillian, Ltd., 1970).

[8]E.W. Merrow, *An Analysis of Cost Improvement in Chemical Process Technologies*, prepared for the U.S. Department of Energy (Santa Monica, CA: RAND Corporation, May 1989), pp 12, 13. There is also the opposing argument that monopoly and concentration generate the freedom and profits that fuel innovation.

[9]R.W. Hess, *Review of Cost Improvement Literature with Emphasis on Synthetic Fuel Facilities and the Petroleum and Chemical Process Industries*, pp. 113 ff.

[10]M. DeLallo (Parsons Power Group, Inc., Reading, PA), "Pulverized Coal Plants Cost and Performance," presentation to the Energy Information Administration, Coal Power Systems Technology Workshop (Washington, DC, February 5, 1997).

[11]Personal conversation with Paul White, Vestas-American Wind Technology, Inc., April 11, 1997.

- ORMAT is a U.S.-based geothermal equipment producer, site developer, and operator with Israeli affiliates. Half its current geothermal capacity is located in the United States. The firm operates primarily outside the United States; nevertheless, 50 to 80 percent of the equipment used on ORMAT projects is produced in the United States and is identical from site to site, wherever ORMAT plants are located.[12]

The same firms illustrate evident learning across borders by people and firms. To varying degrees, each firm not only supplies equipment but also provides design and engineering, construction, and operations services. In some instances, the firms own and operate generating facilities:

- For project installations, Vestas employs expertise and crews drawn from Vestas group (eight Vestas companies) locations around the world.

- Regardless of site location, ORMAT uses the same staff for overall plant architecture and design (although local skills are used for detailed engineering and construction). Key operating staff for new facilities are drawn from experienced staff elsewhere; local staff are used in less critical positions and for day-to-day operation of new sites.

International Learning in the *Annual Energy Outlook 1998*

Because evidence supports international learning, EIA will introduce an international learning component for the *Annual Energy Outlook 1998* (*AEO98*). When instances of the defined new technologies occur outside the United States, their installation will contribute to lower capital costs for those within the United States.

EIA is revising the overall NEMS learning function for use in *AEO98*. The methodology for international learning will be modified as necessary for consistency with the revised general function. Actual experience in using the international component may also result in revisions.

Methodology

In NEMS, foreign units of new technologies will be subject to the same learning function and the same modeling code as domestic units. Revisions to the NEMS learning function for *AEO98* will also apply to international learning.

International units that match each technology definition will be included—up to a limit equal to one unit per year (see "Effects of Time" below)—if they contribute to lowering the first-of-a-kind cost for that technology as used in NEMS. In practice, EIA includes those units of defined new technologies which (1) are generally recognized as being important commercial or demonstration pioneer units that contribute to lowering costs, regardless of when they entered service; (2) entered service in 1996 or after; or (3) were under construction as of May 1, 1997. Moreover, recent years' experience indicates that planned units not under construction, even if under contract, are too uncertain to include. Recent years' repeated delays in construction of planned nuclear, coal-fired, geothermal, and wind plants illustrate the uncertainty of such plans.

EIA has assessed each international unit of capacity with respect to the participation of its sources in the U.S. market. Each international site can be included in the learning function, at its limit as the full equivalent of a U.S. plant (weight = 1.0). In each case, the capacity (net summer capability) for an international unit is an aggregation of primary weights defined with respect to (1) equipment, (2) design or construction personnel, and (3) owning or operating personnel. Each primary weight is arbitrarily equal to one-third of the total weight; weights for design and construction and owning and operating can be subdivided into one-sixth weights (0.165). Tables in the sections below show the weighted international capacity for each technology and the weight assigned each known plant.

The components of each international instance of new technology are weighted as follows:

Equipment (0.000 to 0.333): If the firm manufacturing the equipment (usually the turbine) used in a foreign installation also competes in the United States, it will contribute to U.S. learning. The firm need not be headquartered here; nor must the equipment be manufactured here; nor must there be any actual domestic installations in place or planned, so long as the manufacturing firm competes in the United States. The weights for equipment are likely to be either 0 or 0.333, representing whether or not it contributes to U.S. market learning.

Design and Construction Personnel: If a firm (a) designing or (b) constructing the international plant competes in the United States, EIA assumes that key personnel and important information are transmitted within the firm to any new plants built in the United States by that firm. Therefore, weights for design or construction are

[12]Personal conversation with Dan Schockett (ORMAT), April 15, 1997.

each likely to be 0.000 or 0.1665. Decisions for each (design or build) subweight are based on the names of the firms involved.

Owning and Operating Firms: If a plant is owned or operated by a firm also competing in the United States (whether or not it actually owns or operates a U.S. facility), learning from plant to plant within the firm is assumed to occur through movement of key personnel and information sharing. Weights for ownership or operation are likely to be 0.000 or 0.1665. Again, decisions are based on the names of the firms involved.

Effects of Time: The effects of time are also incorporated in the NEMS international learning function. Where many units are being designed and installed at the same time, it is unlikely that their individual experiences afford notable learning to the others. To incorporate timing effects in the NEMS function, for any technology, international learning effects are limited to the accumulated effect of a maximum of one unit per year, regardless of the actual numbers of units installed that year. For example, if in a given year new geothermal capacity, weighted, exceeds 50 megawatts, its effect on learning will be limited to 50 megawatts for that year as representative of all learning effects for that year's new capacity.

New International Generating Capacity

In NEMS, the learning function applies to the following "new" grid-connected central station electricity generation technologies:[13]

- **Advanced Clean Coal (Gasification.** Integrated gasification combined-cycle (IGCC), with a heat rate no greater than 8,470 British thermal units (Btu) per kilowatthour; at commercial scale, 500 megawatts. Excludes pressurized fluidized-bed units. For learning, advanced units can be coal- or other fossil-fueled.

- **Advanced Combined Cycle.** New combined-cycle power plants with heat rates no greater than 6,900 Btu per kilowatthour; at commercial scale, 400 megawatts; at least equivalent to General Electric "G" frame, including Westinghouse "G," Mitsubishi "501G," and ABB "GT-24/GT-26."

- **Advanced Combustion Turbine.** New aero-derived combustion turbines with heat rates no greater than 9,700 Btu per kilowatthour; at commercial scale, 200 megawatts; at least equivalent to General Electric "G" frame, including Westinghouse "G," Mitsubishi "501G," and ABB "GT-24/GT-26."

- **Molten Carbonate Fuel Cell.** Any molten carbonate fuel cell with a heat rate no greater than 6,000 Btu per kilowatthour; at commercial scale, 10 megawatts.

- **Nuclear.** Any nuclear technology meeting or exceeding AP600 safety and efficiency standards; at commercial scale, 1,300 megawatts. Excluded are recent and planned nuclear units in Japan, South Korea, and Taiwan using evolutions of earlier designs.

- **Solar Thermal.** Grid-connected, centrally dispatched, central station or distributed units—for example, any of solar trough, central receiver (power tower), or dish-Stirling, with or without energy storage, solar only or hybrid—with solar energy conversion efficiency averaging at least 15 percent; at commercial scale, at least 200 megawatts.

- **Solar Photovoltaic.** Grid-connected, centrally dispatched photovoltaic, including central station or distributed units; module efficiencies of at least 12 percent (nonconcentrating); at commercial scale, at least 5 megawatts; excludes off-grid photovoltaics.

- **Wind.** Any grid-connected, centrally dispatched array, achieving energy conversion efficiency of at least 72 percent; at commercial scale, at least 50 megawatts. In practice, at least equivalent to Kenetech 33MVS or Zond Z-46.

- **Geothermal (Evolutionary).** High-temperature dual flash or moderate temperature binary, with a contracted capacity factor of at least 90 percent for dual flash or 85 percent for binary; commercial scale, 50 megawatts. "New" geothermal facilities are evolutions of existing technologies.

- **Biomass Integrated Combined Cycle.** Integrated gasification combined cycle technologies with heat rates no greater than 8,900 Btu per kilowatthour; at commercial scale, 100 megawatts; uses the same gasification technology as coal gasification.

International Data

With assistance from the U.S. Department of Energy fossil, nuclear, and renewable energy offices, and others, EIA has identified "new" domestic and international generating facilities. Table 1 summarizes the identified new capacity either already in service or

[13]For additional specifications, as used in *AEO97*, see Energy Information Administration, *Assumptions for the Annual Energy Outlook 1997* (Washington, DC, December 1996), pp. 58 ff. Revisions for *AEO98*, partially reflected in this paper, are ongoing.

Table 1. U.S. and International Generating Capacity, New Technologies
(Megawatts)

New Technology[a]	Required for Maturity[b] (*n*)	U.S. Capacity		International Capacity		Total Contributing to Maturity[c]
		Current	Planned	Current	Planned	
Advanced Clean Coal (Gasification)	2,500	403.8	0	0	0	403.8
Advanced Combined Cycle	2,000	0	0	0	4,565.0	778.0
Advanced Combustion Turbine	1,000	305.7	0	265.0	0	368.9
Molten Carbonate Fuel Cell	50	0.4	0	0	0	0.4
Nuclear (AP600)[d]	6,800	0	0	0	0	0
Solar Thermal (Grid-Connected)	1,000	10.0	2.5	0	0	12.5
Solar Photovoltaic (Grid-Connected)	25	0.2	2.6	0	0.2	2.9
Wind	250	36.0	113.5	5.2	90.8	138.6
Geothermal	250	34.0	2.5	72.0	538.0	107.7
Biomass Integrated Combined Cycle	500	65.0	16.0	6.0	0	83.0

[a]For EIA's international learning component, enumerations of capacity for new technologies include either units of the technology entering service during or after 1996 or—if the new technology is clearly distinct and there are commonly recognized pioneer units—pioneer units installed before 1996.

[b]For a description of EIA's estimates of first and *n*th unit costs, as well as other characteristics of new generating technologies, see Energy Information Administration, "Electricity Market Module," in *Assumptions for the Annual Energy Outlook 1997* (December 1996), web site ftp://ftp.eia.doe.gov/pub/forecasting/aeo97/aeo97asu.pdf.

[c]Total may be less than sums of individual capacities, because international capacities are reduced by weighting factors, and all capacities are subject to annual limits. See Table 3 for weights. A maximum of 20 percent of the capacity required for maturity is accepted as contributing to maturity in any one year.

[d]Excludes recent and planned nuclear units in Japan, South Korea, and Taiwan using evolutions of earlier designs.

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

expected to enter service over the forecast period. Table 2 lists specifically known U.S. sites. Table 3 lists known international sites.

In practice, the identified "new" facilities approximate, rather than precisely match, the definitions. First, actual units tend to be smaller than defined, primarily because they are often test and demonstration units. Differences often apply to the characteristics of licensing and approval, or to the costs and characteristics of balance-of-system components. Differences may or may not affect learning. Second, distinctions between current and new technologies are not always clear in practice. New geothermal units are not generically different from earlier facilities, but they show cumulative improvements in overall efficiency over time. Similarly, photovoltaic units reflect gradual improvements in module or balance-of-system manufacture, in mounting and tracking equipment, or in siting and controlling characteristics. Huge technology leaps separating new facilities from older units are not the norm. Finally, obtaining data on expected energy conversion efficiencies for new units is difficult.

Using vintage to approximate "new" technologies operating or expected to operate in U.S. and international markets, Table 1 shows new installations entering service during or after 1996. Where the facility obviously matches EIA definitions, regardless of vintage, it is included in Table 1. Table 1 is restricted to new units either actually operating or under construction and does not include facilities that are only under contract, agreement, plan, proposal, or projection. Recent U.S. domestic experience of repeated delays for planned new fossil, nuclear, and renewable energy facilities prompts EIA to exclude them.

The columns used in Table 1 are defined as follows:

- **Required for Maturity (*n*).** Cumulative megawatts of the new technology on line in the United States after which learning effects cease; calculated as the defined plant size for the new technology multiplied by the defined cumulative number of units for maturity, "*n*."

- **Current U.S. Capacity.** Megawatts of U.S. capacity known to be operating as of May 1, 1997. Excludes earlier technology's capacity. Typically—though not always—excludes units entering service before 1996.

- **Planned U.S. Capacity.** Number of megawatts of U.S. capacity known to be under construction as of May 1, 1997 (Table 2). Excludes plans and contracts for which construction has not yet begun.
- **Current International Capacity.** The number of megawatts of international capacity known to be operating as of May 1, 1997. Excludes earlier technology's capacity. Typically—though not always—excludes units entering service before 1996.
- **Planned International Capacity.** The number of megawatts of capacity outside the United States known to be under construction as of May 1, 1997. Excludes reported plans and contracts for which construction has not yet begun.
- **Total Contributing to Maturity (Weighted).** Sum of current and planned U.S. and international capacities contributing to U.S. learning (achieving "*n*"), weighted and with time limits applied (a maximum contribution of one unit—20 percent of the total required for maturity—in any one year). See Table 3 and associated text for weights.

Unresolved Issues

The above learning function explicitly introduces learning from external experience into U.S. technology cost estimations. However, some issues remain to be considered:

- **Unit Size.** In some cases, unit size may overstate learning effects. Especially for first units, plant sizes are often much smaller than the defined commercial unit. For example, new photovoltaic facilities are less than 1 megawatt, whereas the defined size is 5 megawatts. It may be argued that units of drastically smaller size differ substantially from the defined commercial-scale technology and, thus, do not provide full learning effects. On the other hand, because learning effects in NEMS are a function of unit capacity, the learning effects conveyed by small units are also proportionally reduced. Using unit size may also understate learning effects for units smaller than the defined unit size if they are sufficiently large to result in equivalent learning. For example, a 200-megawatt combined-cycle power plant may contain enough modules to convey the same learning as a 400-megawatt unit, yet it will be credited with only half the learning if the defined standard is 400 megawatts.
- **Related Technologies.** Like unit size, the definition of a technology can become significant, resulting in over- or understating of the learning effect. NEMS may overstate learning in some instances, when included new plants are not sufficiently similar. For solar thermal technologies, for example, experience with dish-Stirling technologies may not convey or derive equivalent learning in relation to central station or solar trough generation. On the other hand, NEMS may understate learning when major components also used in other industries are not included in the learning function. The best known example of this exclusion is aircraft turbine development, which contributes significantly to lower electricity generating costs for wind technologies but is not included in the NEMS learning function.
- **Vintage.** In the learning function, NEMS adopts a uniform approach across all technologies. However, "new" may sufficiently vary among technologies to require varying treatment in the NEMS learning function. Some technologies may be distinctly new; fuel cells, advanced nuclear, and coal gasification can fairly easily be distinguished from earlier generations. On the other hand, some technologies may not be clearly separable from earlier units: geothermal, photovoltaic, gas turbine, and solar thermal (trough) technologies may involve a longer continuum of incremental improvements, reflecting an evolutionary path rather than revolutionary advances.
- **Exclusion of Plans, Contracts, and Forecast Results.** EIA's current international learning function includes only actual plants in operation or under construction outside the United States. Domestic learning includes both operating plants and those under construction, as well as new capacity projected by NEMS. Because EIA models are limited to the United States, such an analysis of external demand and supply is missing from the current learning approach, forfeiting recognition of likely new technology expansion in foreign markets. If, for example, reasonable projections of new electricity demand outside the United States clearly indicate likely expansion of a new technology (e.g., advanced combined cycle), the absence of consideration of that expansion understates likely learning effects for that technology in U.S. markets.

Conclusion

EIA recognizes the influence of international experience on U.S. generating technology costs and is incorporating international experience into the NEMS learning function for *AEO98*. Data in this paper show that international experience will lower expected capital costs for new technologies represented in NEMS, sometimes significantly.

Table 2. Current and Planned U.S. Generating Capacity, New Technologies, as of May 1, 1997
(Megawatts)

New Technology	Plant Name	State	Net Summer Capability	Year Online
Current Capacity				
Advanced Clean Coal (Gasification)	Pinon Pine	Nevada	90.0	1996
	Polk	Florida	313.8	1996
Advanced Combined Cycle	—	—	—	—
Advanced Combustion Turbine	Richmond	Indiana	35.6	1992
	Woodland	California	48.0	1993
	South Fond du Lac	Wisconsin	85.2	1994
	Gilbert Station	New Jersey	136.9	1996
Molten Carbonate Fuel Cell	SMUD-HQ	California	0.2	1994
	Kaiser	California	0.2	1994
Nuclear (AP600)	—	—	—	—
Solar Thermal (Grid-Connected)	Solar II	California	10.0	1996
Solar Photovoltaic (Grid-Connected)	Arizona Public Service	Arizona	0.2	1996
Wind	Northern States Power	Minnesota	30.0	1996
	Green Mountain Power	Vermont	6.0	1996
Geothermal	Salton Sea	California	34.0	1996
Biomass Integrated Combined Cycle	Oceola	Florida	65.0	1996
Planned Capacity				
Advanced Clean Coal (Gasification)	—	—	—	—
Advanced Combined Cycle	—	—	—	—
Advanced Combustion Turbine	—	—	—	—
Molten Carbonate Fuel Cell	—	—	—	—
Nuclear (AP600)	—	—	—	—
Solar Thermal (Grid-Connected)	Stirling Test (SAIC)	Arizona	0.02	1998
	Stirling Test (SAIC)	California	0.02	1998
	SMUD	California	2.5	1998
Solar Photovoltaic (Grid-Connected)	Arizona Public Service	Arizona	0.2	1997
	Arizona Public Service	Arizona	0.4	1998
	New York Power Authority	New York	1.0	1997
	New York Power Authority	New York	1.0	1998
Wind	Northern States Power	Minnesota	70.0	1998
	Wisconsin Public Service	Wisconsin	1.0	1997
	Big Spring	Texas	40.0	1998
	SMUD	California	2.5	1998
Geothermal	SMUD	California	2.5	1998
Biomass Integrated Combined Cycle	RTI	Hawaii	1.0	1997
	McNeil Station	Vermont	15.0	1997

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

Table 3. Current and Planned International Generating Capacity, New Technologies, as of May 1, 1997
(Megawatts)

New Technology	Plant Name	Country	Unweighted Net Summer Capability	Year Online	Weight
Current Capacity					
Advanced Clean Coal (Gasification)	—	—	—	—	—
Advanced Combined Cycle	—	—	—	—	—
Advanced Combustion Turbine	BIRR	Switzerland	265.0	1996	0.33
Molten Carbonate Fuel Cell	—	—	—	—	—
Nuclear (AP600)[a]	—	—	—	—	—
Solar Thermal (Grid-Connected)	—	—	—	—	—
Solar Photovoltaic (Grid-Connected)	—	—	—	—	—
Wind	Miyako Island	Japan	1.2	1996	0.5
	Moerdijk	Netherlands	4.0	1996	0.5
Geothermal	Malitbog I	Philippines	72.0	1996	0.165[b]
Biomass Integrated Combined Cycle	Varnamo	Sweden	6.0	1993	0.33
Planned Capacity					
Advanced Clean Coal (Gasification)	—	—	—	—	—
Advanced Combined Cycle	Rocksavage	United Kingdom	720	1997	0.33
	T Point	Japan	330	1997	0.50
	Poryong	South Korea	2,020	1997	0.165
	RDK4S	Germany	360	1998	0.33
	Taranaki	New Zealand	360	1998	0.33
	Dock Sud	Argentina	775	1999	0.33
Advanced Combustion Turbine	—	—	—	—	—
Molten Carbonate Fuel Cell	—	—	—	—	—
Nuclear (AP600)[a]	—	—	—	—	—
Solar Thermal (Grid-Connected)	—	—	—	—	—
Solar Photovoltaic (Grid-Connected)	Two unnamed sites	India	0.20	1998	0.50
Wind	Tetouan	Morocco	50.4	1997	0.5
	Huitengxile	China	5.4	1998	0.5
	Carrickbrock	Ireland	15.0	1998	0.5
	Bessy Bel	United Kingdom	5.0	1998	0.5
	Polwhat Rig	United Kingdom	10.8	1998	0.5
	Siddick	United Kingdom	4.2	1998	0.5
Geothermal[c]	Dieng I	Indonesia	55	1997	0.165[b]
	Salak 3-5	Indonesia	165	1997	0.165
	Malitbog II, III	Philippines	144	1997	0.165
	Upper Mahio	Philippines	119	1997	0.165
	Salak 6	Indonesia	55	1998	0.165
Biomass Integrated Combined Cycle	—	—	—	—	—

[a]Because of unique safety and other requirements imposed on U.S. equipment, no nuclear plants installed outside the United States are considered sufficiently equivalent to U.S. nuclear plants (AP600) to convey any significant learning effects.

[b]On the basis of information obtained from contacts with industry personnel, no currently operating geothermal units outside the United States are considered “new”; however, discovery and drilling techniques are improving, markets are competitive, and firms operating in the U.S. market continue to be involved in all phases of international geothermal development. EIA assigns this limited learning a weight of 0.165.

[c]Because 483 megawatts are slated to enter service in 1997, and their weighted value (80.5 megawatts) exceeds one unit (50 megawatts), geothermal is credited with 50 megawatts for 1997.

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

Electricity Futures in Competitive Electricity Markets: Potential Impacts on Electricity Forecasts

by
David Schoeberlein

As competitive electricity markets evolve, transactions between utilities, independent power producers, and consumers are expected increasingly to be based on prices rather than regulation. As a result, industry participants could encounter new financial risks. Historically, long-term power contracts and rate regulation abrogated the need for the risk management instruments widely used in commodity markets. As regulation diminishes and short-term transactions increase, financial instruments such as forward and future contracts may be called upon to fill the void. The purpose of this paper is to examine the reasons underlying the formation of the West Coast electricity futures market, the impacts that extensive use of futures could have on competitive electricity markets, and the challenges that widespread use of electricity futures will present to the forecasting community.

Introduction

The U.S. electricity industry is moving from a regulated to a competitive market. Prices in the wholesale electricity market are increasingly being set by market forces rather than regulation. Retail consumers are clamoring for direct access to power producers other than their local utilities. Nowhere is the move to competition more apparent than in the role being played by power marketers.[1] In 1996, trading of electricity by power marketers accounted for nearly 2 percent of the $200 billion electricity market. A recent study by Frost and Sullivan[2] predicts that trading volumes by power marketers could reach $40 billion by 2002. If this occurs, some utilities could face stiff competition within their traditional service boundaries from marketers able to supply power to customers at competitive rates.

As competitive forces mature, profit margins for suppliers and marketers could narrow, exposing suppliers to financial risks in the form of stranded generating assets. Conversely, consumers could see electricity prices that fluctuate significantly, based on the availability of and demand for electricity. To optimize profits or minimize expenditures, suppliers and consumers will seek instruments that have the greatest potential to minimize these risks. Futures contracts can be used as a tool for risk minimization and are currently available at two locations—the California-Oregon Border (COB) intertie and the Palo Verde Nuclear Switchyard (Palo Verde).

First, this paper describes futures and examines the evolution of the standard future contract as a financial instrument. Second, it characterizes electricity futures offered on COB and Palo Verde electricity prices. Third, it examines the reasons for the creation of the West Coast futures market. Fourth, it analyzes the prospect of volatile electricity prices under competition and the potential impact of futures as risk management tools. Finally, it discusses the reasons that electricity futures should command attention from utility and other industry forecasters.

Background

What are Futures?

Futures are an agreement between buyers and sellers to take possession of or deliver a commodity or cash at a

[1]Power marketers purchase electricity and transmission services from suppliers (such as utilities and nonutilities) for resale to other suppliers or consumers. These marketers should not be confused with power marketing administrations, which are federally subsidized producers and distributors.

[2]Frost and Sullivan, *Strategies and Issues in the Power Marketing Industry*, Report #5579-14 (Mountain View, CA, February 1997).

specified time and price. They are based on the notion of forward contracts, which were widely used by the agricultural community to protect the ultimate selling price of crops at harvest time. Because large consumers needed a reliable and constant flow of products, they were willing to agree to a forward (or future) price. In this way, both parties shared the risk of crop or price failure due to weather, pests, or adverse market conditions. For example, if farmers decided in April that they would need to get $1.00 per bushel for corn at the June harvest to make a profit, then they sought out large corporate consumers of corn who were willing to agree to that price. Consumers entered into the arrangement because it assured them of a guaranteed supply at a set price—the forward price. Generally, both parties knew each other and agreed to the quantity, quality, place, and time of delivery for the commodity and the method of payment. The buyer was required to find a seller and the seller a buyer.

Forward contracts were business agreements in which the buyer took actual delivery of the commodity if no transferability clause had been negotiated. But if, in the example above, the corn consumer decided in May that June corn might be a bumper crop (with prices well below $1.00 a bushel), then the only way that the consumer could get out of the contract was to find a speculator who believed that the price would remain relatively high. The speculator would buy the contract, but at a lower price per bushel than the consumer's original contract with the farmer. The difference between the original price and price at which the consumer sold the contract to the speculator was the consumer's cost for getting out of the contract. Because these contracts were generally written as business agreements between known parties, they could not easily be transferred. Without transferability, they could not be traded and, therefore, were not liquid.

In contrast, futures are standard legal contracts traded on centralized exchanges. Like forward contracts, futures are standardized as to quality, quantity, price, delivery time, and delivery location. The exchange is associated with a central clearinghouse that takes the contra (or opposite) position of the contract. Consequently, trading is anonymous. Because interested parties need not seek each other out, futures can be traded as quickly as the fastest available means of communication—typically, computer networks or telephone. The combination of standard contracts and a method for clearing transactions is what gives futures their liquidity. Futures are easily transferable. Like stocks, bonds, and other securities, they are traded on major, regulated exchanges.

Anonymity does not mean that futures traders cannot choose a specific trading partner. A transaction called an Exchange of Futures for Physicals (EFP) provides the only legal mechanism to choose a trading partner. In an EFP, the buyer of a cash commodity transfers to the seller of the commodity an equivalent amount of long futures contracts, or receives from the seller an equivalent number of short futures contracts. In market terminology, to "go long" means you are buying the contract, whereas to "go short" means you are selling. Although EFPs can take many forms, the most common occurs when participants effect delivery. At delivery, participants switch their market positions, closing their respective obligations to the exchange.

Using EFPs, the participants can agree to make and take delivery at any location, including the standard locations specified by the exchange. Although the clearing price for the EFP must be submitted to the exchange, the physical transaction is effected at a private, mutually agreed on price. Because of the flexibility of EFPs regarding delivery, partner, and price, most commodity deliveries are conducted by this method. EFPs account for more than 98 percent of energy deliveries for contracts on the New York Mercantile Exchange (NYMEX),[3] which is the exchange that specializes in energy futures contracts.

What are Electricity Futures?

Electricity futures are NYMEX-traded contracts that oblige sellers to make delivery, or buyers to take delivery, of a uniform quantity of electricity at COB or Palo Verde. Before electricity, NYMEX created futures markets in natural gas, crude oil, gasoline, and other energy products as functional spot and cash markets in those products evolved.

Electricity futures prices are based on an index of electricity prices for delivery at two locations—Palo Verde in Arizona and the COB in the Pacific Northwest. Because these facilities provide "gateways" through which northwestern and southwestern power is transmitted to California markets, they are among the most active trading locations in U.S. electricity markets. The index for each location is volume-weighted and calculated using transactions reported by 15 industry participants. Dow Jones began publishing the COB electricity index in June 1995. Currently, both indexes are published daily in the *Wall Street Journal*.

The COB is the location at which utilities in the Northwest connect to California. The AC intertie consists of three 500-kilovolt lines on the south and three 500-

[3]TULE Hub Services Company, "Exchange of Futures for Physicals," web site www.tule.com (not dated).

kilovolt lines on the northern California side. Transmission capacity is rated at 4,800 megawatts north-to-south and 3,675 megawatts south-to-north. The Bonneville Power Administration (BPA) operates the system north of the intertie, and Pacific Gas and Electric (PG&E) manages flows south. Palo Verde is the intertie that connects utilities in the Southwest to California, with capacity to move 6,100 megawatts east and 2,500 megawatts west.

The COB indexes are calculated as the weighted average price of megawatthours sold at the California-Nevada and Nevada-Oregon borders. Indexes are calculated for non-firm on-peak and non-firm off-peak electricity. In addition to non-firm indexes, Palo Verde calculates firm on-peak and firm off-peak prices. Firm electricity is energy sold for delivery at Palo Verde that includes a 1-hour, or greater, recall provision.[4] COB and Palo Verde non-firm electricity is subject to interruption for any reason at any time. Peak hours for both locations are 6:00 AM (06:00) to 10:00 PM (22:00) Monday through Saturday. Palo Verde includes Sunday as an on-peak day.

A single contract for both locations consists of 736 megawatts of peak power in increments of 2 megawatts per hour over 23 business days within each month. Delivery is scheduled beginning at 07:00 and ending at 22:00, with delivery into Saturday and Sunday allowed for months containing less than 23 business days. As with all commodity futures, an initial deposit designed to cover adverse price movements (initial margin) is required when a position is opened. The margin may be submitted as cash, bonds, or letters of credit. NYMEX initial margin rates for clearing members, members, and customers are $1,400, $1,540, and $1,890, respectively. Margins amounts may also change over time as a result of changes in the overall risk of the market. If the value of the position declines, then additional deposits (maintenance margin) are required. If the deposits are not forthcoming, then the position is closed by the exchange.

Electricity and Futures

Impetus for Development of a Futures Market

Passage of the Energy Policy Act of 1992 (EPACT) created a climate in which many energy analysts could foresee a growing move to competition among electricity suppliers. EPACT created a class of suppliers, called "exempt wholesale generators" (EWGs), that can develop non-rate-based generating systems[5] and market the power to utilities. More importantly, by giving EWGs access to utility transmission systems, EPACT created a mechanism for wholesale wheeling. Many industry analysts and commodity traders foresaw retail wheeling as an inevitable next step.

Currently, experiments and plans in open markets are underway in many States. The move to retail wheeling is already well underway in California. FERC Order 888, which requires owners of transmission facilities to post transmission tariffs, has the potential to open the transmission grid and erase traditional service boundary areas. Cogeneration, district heating and cooling, and self-generation in wholesale markets and demand-side management programs in retail markets currently provide consumers with rudimentary mechanisms to manage their power purchases. Consumers want to expand their power supply options by demanding direct access to the transmission grid, where they can negotiate price and services with suppliers other than their local utilities. Power marketers and traders are hoping that open transmission access will inaugurate the classic commodity market condition of supply exceeding demand and, thus, magnify inefficiencies in the current regulated industry. If this occurs, then competition could result in lower but more volatile prices as the price of electricity reacts to shifts in supply and demand and a multitude of other factors, such as extreme weather and power outages.

Price volatility[6] in commodity markets normally accelerates the development of a short-term or cash market for consumers seeking the lowest price and producers seeking the highest price. However, the price that clears the local electricity market during some periods could be high due to strong demand or weak supply. Therefore, consumers would benefit from an instrument that locked in delivery and price during crucial periods. Conversely, suppliers would benefit from a mechanism that assured future supplies and protected revenue targets. Based on its experience in other energy markets, NYMEX believes that futures are the logical choice for such mechanisms.

Electricity futures not only provide a mechanism for responding to competition, they can also accelerate competition. Competition in natural gas markets was accelerated by the introduction of gas futures. The price discovery characteristics of futures led to more efficient spot or cash markets by providing a benchmark against which spot price negotiations could be compared. In

[4]"Recall" means that the supplier or dispatcher intends to interrupt electricity flow temporarily or permanently.
[5]"Non-rate-based" means that utilities do not profit from the asset but pass the purchase price through to consumers.
[6]"Price volatility" is defined here as the statistical variance of the time series of price changes.

essence, the natural gas futures contract is commonly used as an indicator of the physical price of natural gas. Because suppliers and marketers now have a tool that guarantees the price of gas at a future date, natural gas futures have encouraged the development of new products, such as price caps to large industrial users.[7]

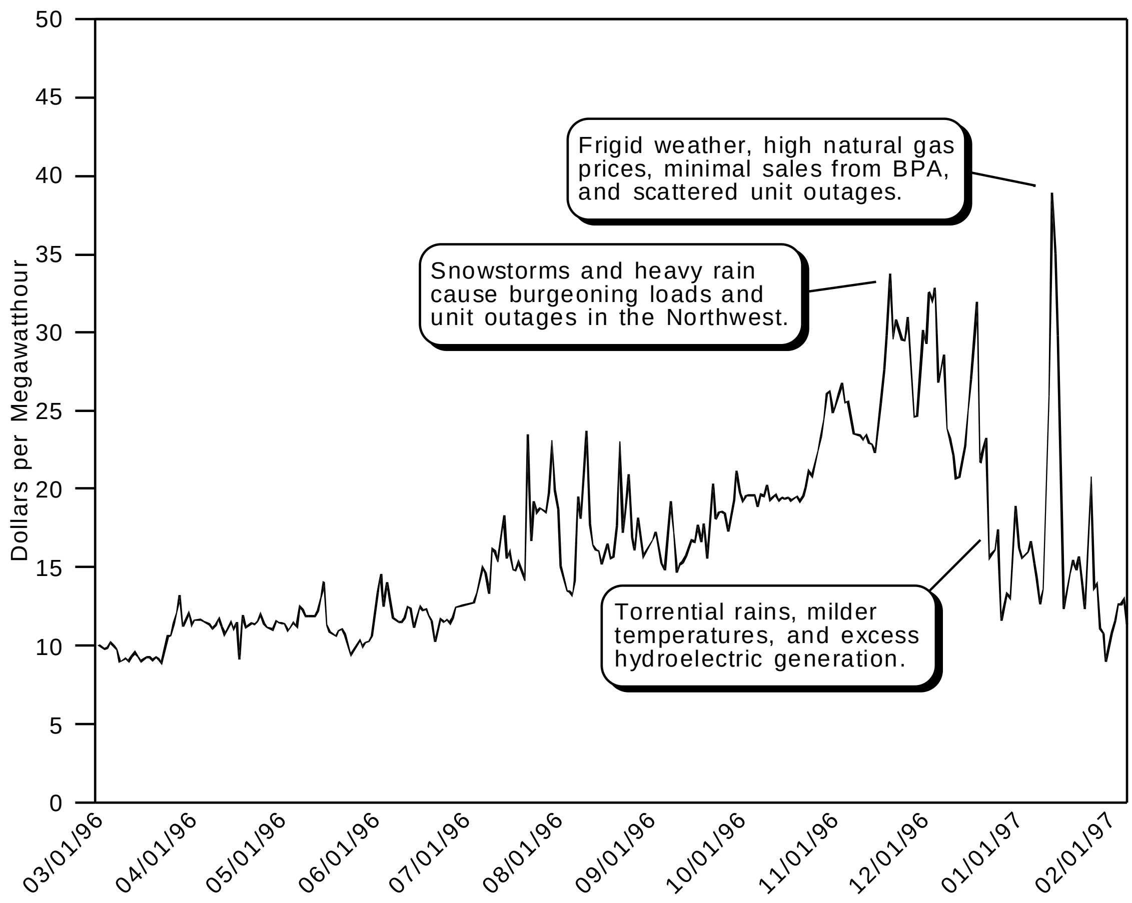
Impact of Electricity Futures in Competitive Markets

The assumption that electricity prices may become more volatile in an increasingly competitive electricity market is suggested by considering the trajectory of COB and Palo Verde index prices (Figures 1 and 2).[8] Since futures trading began, index non-firm on-peak prices have ranged from $8.94 to $38.96 per megawatt-hour at COB and from $7.86 to $46.19 per megawatt-hour at Palo Verde, exhibiting extreme volatility.

Electricity prices are sensitive to weather conditions, fuel prices, and the amount of generating capability available. Demand for electricity fluctuates between the high demand periods of weekday working hours and the relatively low demand of late night and weekend periods. Although utility dispatchers are adept at predicting demand based on time of usage, unanticipated weather conditions can drive demand above normal peak usage for a given season and time of day.

For some generating technologies (such as coal-steam), the time needed to become fully operational can extend several hours after the initial decision to bring the unit online has been made. If dispatchers are caught short, their only alternatives to supply electricity to their customers is to buy or swap power with a neighboring utility, increase their own generating capacity by running units at higher output, or bring idle units that

Figure 1. COB Non-firm On-peak Electricity Price Index, March 1996-January 1997

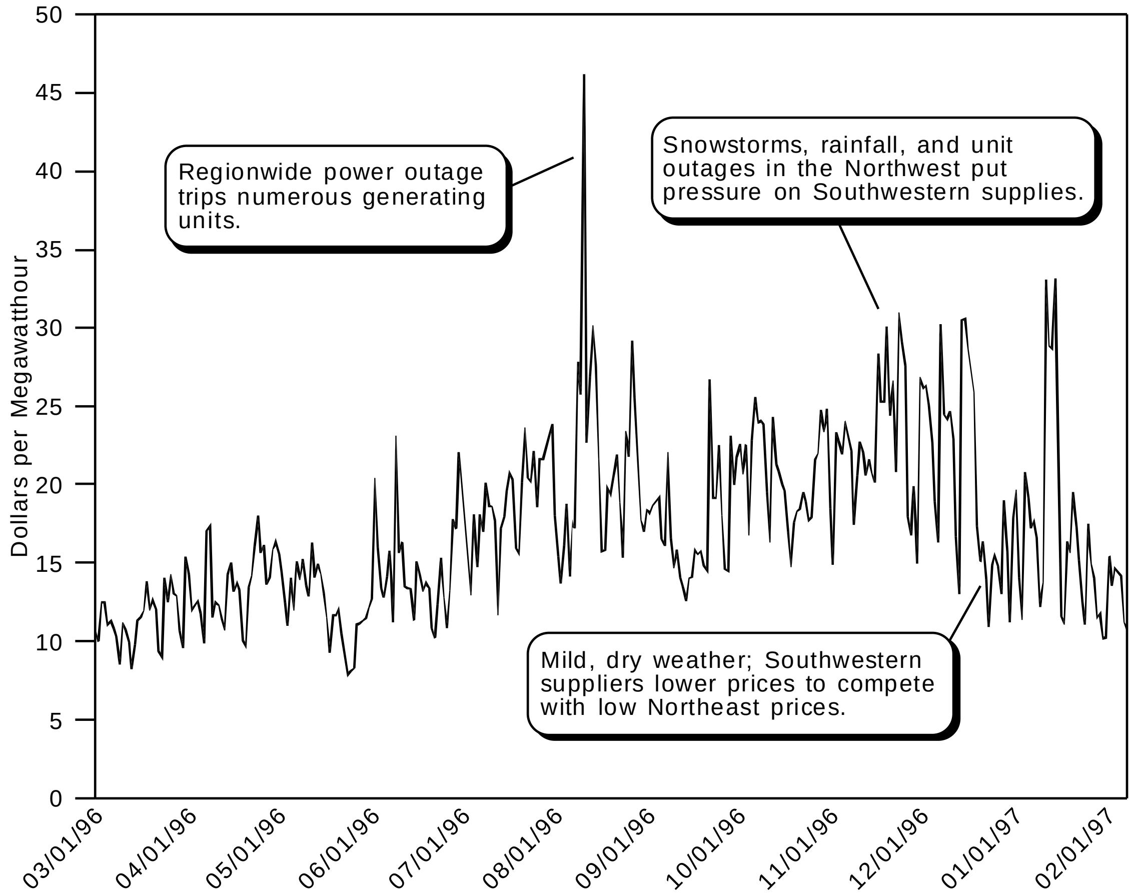


Source: LCG Consulting, "Electric Utility Statistical Database," web site www.energyonline.com (March 1996-February 1997).

[7]J. Sturm, *Trading in Natural Gas* (Oklahoma City, OK: PennWell Publishing, 1997).

[8]Most index values for both COB and Palo Verde are average daily prices weighted by volume of electricity transmitted, based on a minimum number of transactions. However, some of the values included are the result of insufficient trading activity to calculate a definite daily average. Values are also interpolated for days when indexes are not available.

Figure 2. Palo Verde Non-firm On-peak Electricity Price Index, March 1996-January 1997



Source: LCG Consulting, "Electric Utility Statistical Database," web site www.energyonline.com (March 1996-February 1997).

serve as reserve margin online if time allows. Swapping or "borrowing" power from a neighboring utility allows the utility to satisfy its current demand and "pay back" the power at a later date. However, in the case of unanticipated peaks due to unusually hot or frigid weather, there is no guarantee that neighboring utilities will not be suffering the same shortages. When this occurs, the spot price of electricity rises in proportion to the severity of the shortage. Conversely, a glut of excess generation capability (for example, from hydroelectric plants whose lakes are ready to spill water) or mild temperatures can drive the price of electricity down.

Analyzing the reasons for the "spikes" and "canyons" of daily spot prices in Figures 1 and 2 provides information about the magnitude of price swings that may occur under competition in other locations. For example, prices skyrocketed at Palo Verde during the second week of August 1996 due to baking temperatures over much of California (on several days, temperatures exceeded 100 degrees) and a nine-State power outage as a heavily overloaded transmission line sagged into trees. The transmission outage, in turn, caused a number of fossil and nuclear units to trip offline, further exacerbating the situation. Although the non-firm on-peak index for the worst day reached more than $46 per megawatthour, prices for 16-hour blocks of firm energy at Palo Verde exceeded $90 per megawatthour, triggering huge shifts of energy between the Northwest and Southwest as attempts were made to use a transmission system designed for reliability as a profit maximizer. Conversely, prices plummeted during the last week of December 1996, when milder temperatures and holiday schedules drove prices at COB from more than $30 per megawatthour to less than $16 per megawatthour.

The above analysis is not meant to imply that the COB and Palo Verde electricity markets can be used as a comprehensive proxy for future competitive electricity markets. These markets exist primarily to serve California, which has taken the lead in competitive markets by being the first State to provide a timeline for full retail access. However, power marketers are aggressively offering power supply contracts to large power consumers outside the Western Power Exchange (WEPEX),[9] while consumers within WEPEX are sending out requests for power.[10] The assumption that competition would occur first in western markets is the reason that NYMEX chose this area to launch the first-ever electricity futures market. Given the volatility displayed in this region so far, coupled with the imminent collapse of traditional utility service boundaries, risk-averse suppliers will seek to lock in prices to protect future revenues, and risk-averse consumers will likewise attempt to lock in prices to avoid price spikes.

The methods by which suppliers and consumers protect revenues and expenditures could have a significant effect on the price of electricity in a competitive market. This can be demonstrated in a few concrete (but idealized) examples. Suppose that a power producer forecasts that, next month, electricity will sell below the current price of $11 per megawatthour. The producer can sell a futures contract, offering to sell 736 megawatthours at the prevailing price of $11 per megawatthour ($8,096 for the contract).

- If the producer's forecast is correct and the price falls to $8 per megawatthour, then the producer sells electricity at this lower price in the cash market, realizing $5,888, and buys back the futures contract, which is now valued at $8 per megawatthour (or $5,888 for the total contract). The producer receives $5,888 dollars from the cash market and a $2,208 gain from the futures transaction (selling at $8,096 and buying at $5,888) effectively maintaining a revenue target of $11 per megawatthour.
- On the other hand, if next month's price for electricity climbs to $12 per megawatthour, then the producer will sell the electricity in the cash market (realizing $8,832 for 736 megawatthours) and also buy back the futures contract at this elevated price ($8,832). Again, the cash market sale ($8,832) minus the futures market loss of $736 (sells at $8,096 and buys at $8,832) effectively locks in a price of $11 per megawatthour, matching budgeted revenue.

In both cases, the producer buys back the future to "offset" the effect of selling a future. This strategy removes the producer's responsibility to stand for delivery of electricity in the futures market and dampens the risk of inadequate future revenue when selling in what may become a volatile cash market under competition. By providing some measure of revenue protection, utilities might be able to use these hedging strategies to reduce the amount of existing generating capacity that is expected to become uneconomical in a competitive environment. Estimates of these so-called "stranded assets" exceed $200 billion.[11] While it may be unrealistic to presume that futures strategies could fully mitigate losses of this magnitude, hedging strategies could play a role in extending the economic lives of generating assets near the "stranded" threshold.

Challenges for the Forecasting Community

Futures are forecasts. Futures prices are the synthesized predictions of commodity prices by buyers and sellers in the market. Although trading on exchanges is anonymous, the prices at which the trades occur are open to everyone. In mature markets, as the time remaining for delivery of the commodity diminishes, the value of the futures contract should approach the actual commodity price. Consequently, even nonparticipants can benefit from this "price discovery" characteristic of futures trading.

Forecasters, in particular, can benefit from the collective predictions supplied by a futures market. Figure 3 demonstrates this forecasting characteristic of futures. Although COB electricity index prices ranged from $10 to $15 per megawatthour in June 1996, electricity futures for August delivery during the same period were offered at significantly higher prices. Clearly, traders were anticipating higher prices in August, based on their collective prediction of the behavior of the market—a prediction that was largely borne out by prices in August that were higher than June prices.

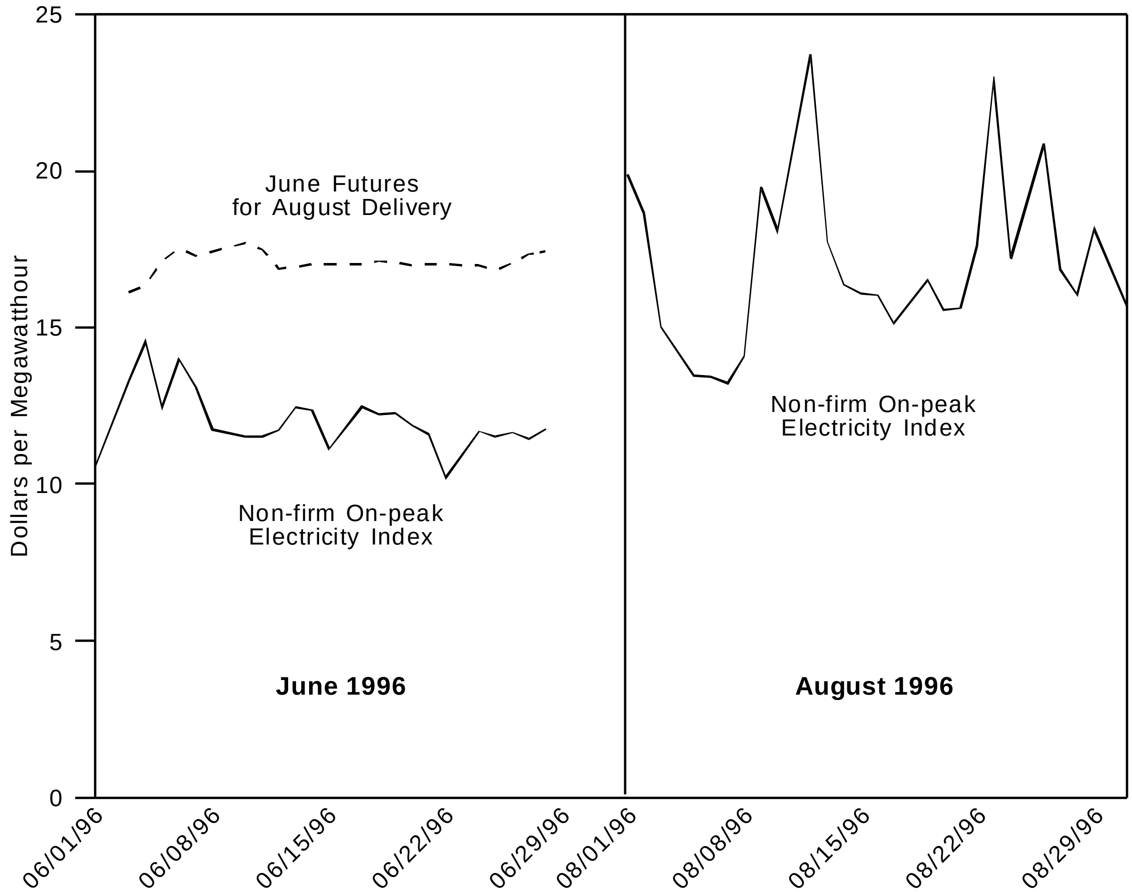
By understanding the collective assumptions that drive futures prices, forecasters can gain valuable insight into the authentic determinants of electricity price in a competitive market. Market-based models that rely solely on the intersection of supply and demand to determine electricity price and do not take into account the possible strategies that might be employed to smooth the industry's transition to competition may be ignoring

[9]The Western Power Exchange (WEPEX) is an association of California electricity industry stakeholders organized by Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric. On December 20, 1996, the California Public Utility Commission (PUC) ordered these three investor-owned utilities to file applications with the FERC to establish a unified power grid operated by an independent system operator (ISO) and a public hourly spot market for bulk power operated by the Power Exchange (PX).

[10]B.F. Roberts, "Load and Revenue Analysis and Forecasting for Restructured Electricity Markets," Presented to the Electricity Utility Forecasters Forum (Santa Fe, New Mexico, October 24, 1996).

[11]Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, DOE/EIA-0562(96) (Washington DC, December 1996), p. 52.

Figure 3. COB Electricity Price Index and Futures Prices, June and August 1996



Source: LCG Consulting, "Electric Utility Statistical Database," web site www.energyonline.com (June 1996 and August 1996).

an important dimension of the new environment. And although the impacts of supply and demand on commodity markets can never be discounted, the rivalry inherent in competition implies that market participants will employ every advantage to build and keep market share while minimizing expenses. The challenge that industry forecasters face is in discerning those strategies that promise the greatest return for market participants.

Conclusion

The risk management and price discovery characteristics of electricity futures may provide power producers and consumers with a valuable tool to maintain revenue, reduce risk, and smooth the transition to competitive markets. The extent to which trading instruments will be used in the future is unknown, but the extent to which electricity markets will deregulate is similarly obscure. Direct open access to many suppliers could introduce price volatility as a transmission network designed for limited interregional flows is transformed into an integral component of a "profit machine". Rival suppliers are expected to employ every advantage at their disposal to build and maintain market share. Whether electricity futures will be a significant advantage will become apparent only as the market evolves. Forecasters should monitor the development of the electricity futures market and measure its impact as competitive electricity markets evolve.

Forecasting *Annual Energy Outlook* Coal Transportation Rates

by
Jim Watkins

Coal transportation rates are an important element of the Annual Energy Outlook 1997 (AEO97)[1] *forecast because the shipping charges associated with coal transportation are a major component (along with minemouth prices) of the delivered price of coal and, consequently, an important determinant of coal distribution patterns. This paper examines the new methodology used to forecast coal transportation rates for the* AEO97. *The new method is based on the producer price index (PPI) (from the Bureau of Labor Statistics) for coal transportation by rail to all end-use sectors. It differs from the methodology used prior to* AEO97 *to project coal transportation rates strictly on the basis of input costs. The cost-based rate indexing methodology was satisfactory for capturing railroad input cost trends, but it failed to account adequately for transportation productivity trends. The new methodology, based on PPI data, incorporates improvements in railroad transportation productivity, as well as changes in input costs.*

Background

The National Energy Modeling System (NEMS) explicitly incorporates coal transportation rate trends in the development of coal forecasts and analyses. The Coal Distribution Submodule (CDS), a component of the NEMS Coal Market Module, is used to simulate the transportation and distribution of coal. The CDS distribution network consists of 11 coal supply regions and 13 coal demand regions, resulting in 143 possible coal shipment routes from coal supply to demand. The CDS uses a linear program to establish coal transportation and distribution patterns within the *Annual Energy Outlook* (*AEO*) forecast. The procedure finds the distribution pattern that yields minimum delivered cost for a transportation network of *n* supply regions and *m* demand regions.

Initial transportation rates in the CDS are represented at the interregional level of detail and represent the difference between coal minemouth prices and delivered prices for a particular year that is chosen as the base year. The base-year rates on the CDS network are indexed over time for each year in the forecast. Indexing factors are applied to the base-year coal transportation rates in order to capture future changes in real coal transportation rates relative to general inflation. The indexing factors are applied uniformly over five economic demand sectors: electric power generation, industrial steam generation, coal coke manufacturing, residential/commercial consumption, and coal exports.

Prior to the *Annual Energy Outlook 1997* (*AEO97*), the indexing factors for coal transportation rates were based on index data for railroad input operating costs, published by the Association of American Railroads (AAR). For the *AEO97*, a revised methodology, based on the U.S. Department of Labor, Bureau of Labor Statistics (BLS), producer price index (PPI) for coal transportation, was used for coal transportation rate indexing. This PPI-based methodology tracks the national average changes in prices received by railroad companies for the transport of coal.

The PPI was incorporated into the methodology not only because it measures changes in the prices charged by railroads for the transportation of coal but also because it can be used to correlate transportation rate changes with other statistical measures in the industry, such as level of employment, revenue earnings, operating costs, and productivity. Many coal transportation rates are tied to coal transportation contracts that have escalation clauses to provide for price adjustments. Thus, the PPI-based methodology is expected to provide proper adjustments to coal transportation rates across various scenarios.

[1]Energy Information Administration, *Annual Energy Outlook 1997*, DOE/EIA-0383(97) (Washington, DC, December 1996).

The methodology assumes that the statistical relationship between the PPI for coal transportation and railroad productivity gains will continue over the forecast horizon. Absent any improvement in productivity, the methodology assumes that increases in the prices of railroad transportation inputs will raise the price that shippers pay to transport coal and, conversely, that improvements in railroad productivity will reduce the price of transportation services.

The methodology consists of a statistical regression model fitted to the historical PPI series obtained from the BLS. The key independent variables for this model are diesel fuel cost, transportation equipment cost, wage cost, and a time trend that is intended to capture changes in railroad productivity for coal transportation. The resulting output—the projected PPI or rate indexing factor—reflects both projected changes in input costs and growth in railroad productivity that is expected to result from increased fuel efficiency, technology improvements, more efficient capital equipment, reduction in the workforce, and reengineering of the railroad industry through cost-cutting means such as consolidations and greater use of unit trains.[2]

This paper presents, first, the underlying rationale for the indexing of coal transportation rates, followed by an analysis of the trends in some of the variables that influence coal transportation costs and rate-setting strategies, and how they relate to the coal transportation rate indexing methodology. It then discusses the revised coal transportation rate indexing methodology and presents results, conclusions, and tables that contain historical input data and regression statistics.

Rationale for Coal Transportation Rate Indexing

The objective of indexing coal transportation rates is to produce a time series of coal transportation rates consistent with the economic, competitive, and related market conditions that are likely to prevail within the coal industry over the forecast period. Railroad companies set coal transportation rates in response to incurred costs of primary inputs, market competition, industry productivity, and other industry and technological factors. The level at which transportation rates are set is closely tied to the ability of railroads to earn revenues adequate to cover operating costs and provide a reasonable return on capital.

The Staggers Act of 1980 partially deregulated the railroad industry and accorded the industry greater freedom to raise and lower transportation rates in response to inflation and market conditions, without regulatory control. The Act limited the jurisdiction of the Interstate Commerce Commission (ICC), now the Surface Transportation Board (STB), over maximum rates to cases in which revenues exceed 180 percent of variable costs. The Staggers Act also permitted railroads to change their rates, without challenge, in accordance with a railroad cost adjustment factor (RCAF). The RCAF was to be set by the ICC to account for inflation in the cost of inputs. Revenue-inadequate railroads could increase their rates by an additional 4 percent above the RCAF. Subject to these constraints, carriers were authorized to increase rates to respond to cost increases without ICC review. The ICC was authorized to prescribe a rate index or percentage index that would be available to all carriers to cover inflationary cost increases. Shippers and carriers were permitted to enter into contracts for rates and services with indexing clauses that allow the parties to adjust rates based on market conditions.[3]

Trends in Factors That Influence Rate Setting and Indexing

Several measures of railroad productivity and cost change were analyzed in the process of developing the PPI-based econometric model for projecting future changes in coal transportation rates. The analysis examined railroad labor productivity, railroad multifactor productivity, railroad ton-miles per gallon of fuel consumed, the RCAF, railroad cost recovery (RCR) indexes, the railroad all-inclusive cost index (AII), and how each affects coal transportation rates.[4] Particular attention was given to the railroad PPI for coal transportation and its relationship to the measures of railroad productivity and railroad combined inputs (i.e., capital, intermediate purchases, wages and fuel, and

[2]U.S. Department of Labor, Bureau of Labor Statistics, *Multifactor Productivity Trends for Selected Industries* (Washington, DC, December 1996).

[3]U.S. General Accounting Office, *Railroad Regulation—Economic and Financial Impacts of the Staggers Rail Act of 1980* (Washington, DC, May 1990); Association of American Railroads, Economics and Finance Department, *Railroad Freight Rates in the Five Years Since Staggers* (Washington, DC, February 1986); and J.W. Lawson, "Rail Contract Rate-Making and Deregulation," Presentation at Coal Outlook Conference (Washington, DC, November 11, 1980).

[4]Although several of the productivity measures relate to all railroad traffic, coal accounted for 39 percent of total railroad traffic in 1994. Between 1985 and 1994, the share has ranged from a low of 38 percent in 1988 to nearly 41 percent in 1990 (Association of American Railroads, *Railroad Ten-Year Trends*, Washington, DC, 1995). Railroads transported slightly over 57 percent of all domestic coal in 1995 (Energy Information Administration, *Quarterly Coal Report*, DOE/EIA-0121(95/4Q), Washington, DC, May 1996, Tables 6 and 12).

materials and supplies). Emphasis was placed on the PPI for rate indexing because it plays a significant role in the negotiation of coal transportation contracts. The PPI is also of interest because it is measured monthly by the BLS[5] and is widely recognized among businesses, economists, statisticians, and accountants as an objective measure of prices in the marketplace.

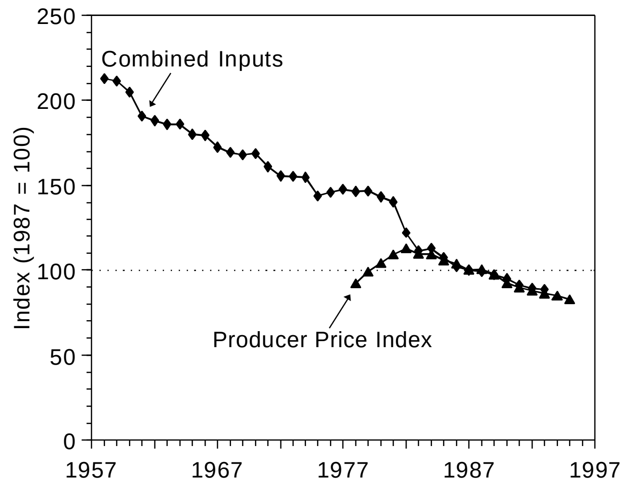
The PPI for coal transportation measures the average change in prices received by railroads for the transport of coal throughout the United States. It is calculated by the BLS from transportation price reports provided to the BLS by railroad companies. A random sampling of railroad companies is conducted by the BLS to obtain the data for this index.[6] The PPI for coal transportation can be used in the indexing of long-term coal transportation contracts in which both parties agree that the contract price will be adjusted periodically in proportion to changes in the PPI series.

Since 1982, both the PPI for coal transportation and the index of railroad combined inputs have been declining, and the trend in the PPI has been parallel to the index of railroad combined inputs (Figure 1). (Between 1980 and 1982, however, the two indexes were divergent. This could have been in response to passage of the Staggers Rail Act of 1980; high railroad fuel costs, which increased by 15 percent in this period; or railroad wage costs, which increased by 26 percent.)

One major reason for the decline in the PPI is that railroad labor productivity has been increasing. The inverse relationship between the PPI for coal transportation and railroad labor productivity is incorporated into the transportation rate indexing methodology. Railroad labor productivity is a measure of the change in the ratio of the output index (based on a composite, revenue-weighted average of the year-to-year changes in ton-miles for various segments of traffic in the ICC / STB Waybill[7]) over the labor input index.

The effect of multifactor productivity has also been incorporated into the transportation rate indexing methodology. Railroad multifactor productivity is a measure of output per unit of combined inputs and relates railroad output to the combined inputs of labor, capital, and intermediate purchases.[8] Capital includes the services of equipment (such as freight cars), structures (such as tracks), land, and inventories. Intermediate purchases include materials, fuels, electricity, and purchased services.

Figure 1. Trends in Railroad PPI for Coal Transportation and Index of Combined Inputs, 1958-1995



Source: U.S. Department of Labor, Bureau of Labor Statistics, *Multifactor Productivity Trends for Selected Industries* (Washington, DC, December 1996).

Multifactor productivity (Figure 2) for railroad transportation has steadily increased over time, and the analysis showed that the growth in multifactor productivity has been closely matched by the growth in output per unit of capital and the growth in output per unit of intermediate purchases. Whereas intermediate purchases input has increased slightly in the presence of these improvements, capital input has been decreasing, and labor input has fallen even more rapidly than capital input. The substitution of capital and intermediate purchases for labor has been an important factor in labor productivity growth in the railroad industry. These productivity improvements are incorporated in the projected transportation rate index factors.

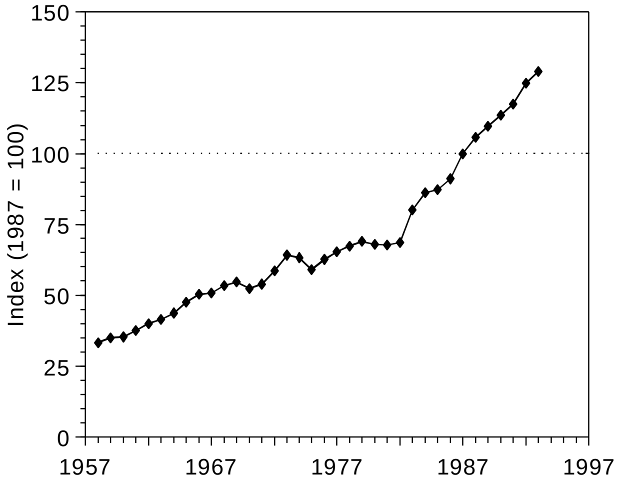
[5]Although the PPI from the BLS for coal transportation represents only rail transportation, analysis of coal transportation data from the EIA Coal Transportation Rate Data Base (CTRDB) indicates that the composite PPI for all modes of coal transportation has been declining since 1984. The CTRDB represents utility coal transportation by all types of rail, barge, truck, conveyor, and various combinations of these modes. Data for the CTRDB are collected on Federal Energy Regulatory Commission (FERC) Form 580, "Interrogatory on Fuel and Energy Purchase Practices," survey pursuant to Section 205(f)(2) of the Federal Power Act of 1920.

[6]U.S. Department of Labor, Bureau of Labor Statistics, *The Producer Price Index: An Introduction to Its Derivation and Uses* (Washington, DC, March 1989).

[7]A waybill is the document covering a shipment and showing the forwarding and receiving stations, the name of consignor and consignee, the car initials and number, the routing, the description and weight of the commodity, instructions for special services, the rate, total charges, advances, and waybill reference for previous services, and the amount paid.

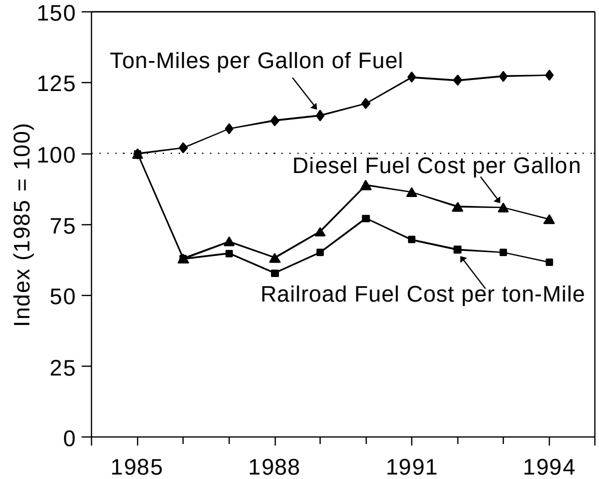
[8]U.S. Department of Labor, Bureau of Labor Statistics, "Multifactor Productivity in Railroad Transportation," *Monthly Labor Review* (August 1992).

Figure 2. Multifactor Productivity for Railroad Transportation, 1958-1993



Source: U.S. Department of Labor, Bureau of Labor Statistics, *Multifactor Productivity Trends for Selected Industries* (Washington, DC, December 1996).

Figure 3. Indexes of Railroad Coal Transportation Cost Inputs, 1985-1994



Source: Association of American Railroads, *Railroad Ten-Year Trends 1985-1995* (Washington, DC, 1995).

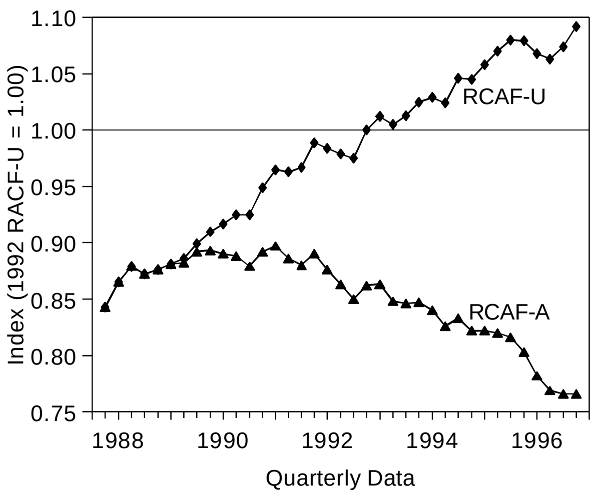
Another reason for the productivity improvement that is reflected in the projected transportation rate index factors is the efficiency gain in fuel cost per ton-mile, which is determined by the product of the fuel cost per gallon and the fuel usage rate as measured in gallons per mile (Figure 3). Fuel cost plays an integral role in the delivery of railroad transportation and transportation rate setting and is a major component of railroad intermediate purchases. In recent years, railroad companies have been able to increase their freight ton-miles per gallon of fuel consumed at a relatively stable pace (Figure 3). Fuel efficiency came from the use of more efficient modern diesel engines that produce twice as much power as earlier diesels.[9] Also, larger and lighter aluminum cars have contributed to the lowering of the fuel cost per ton-mile.

A brief analysis of the Railroad Cost Adjustment Factor Adjusted (RCAF-A), the RCR series, and the AII was also performed. These indexes, computed by the AAR and the STB, play an important role in coal transportation rate setting. The RCR measures changes in the price that railroads pay for: labor, fuel, materials and supplies, equipment, rent, purchased services, depreciation, interest, taxes, and wage supplements. The AII measures changes in the price that railroads pay for each component of the RCR plus casualties, insurance, loss and damage, taxes other than income and payroll, and general and administrative expenses. The RCAF is the ICC/STB term for the AII divided by 100.[10]

The AII is filed with the STB by the AAR. The STB develops the RCAF from the AII series. Starting in the second quarter of 1989, the ICC (now the STB) started developing an adjusted RCAF (the RCAF-A) to reflect gains in productivity. The RCAF-A is obtained by dividing the RCAF Unadjusted (RCAF-U) by a productivity adjustment factor (PAF). Figure 4 shows the relationship between the RCAF-A and the RCAF-U. If railroad transportation rates track the RCAF-U, then one can assume that railroad transportation rates have been increasing over time. However, a productivity adjustment makes a significant difference in the RCAF-A, and if rail transportation rates track the RCAF-A then one can conclude that there has been a downward trend in rates. The downward trend in the RCAF-A is expected to continue because activities such as the accelerated pace of line sales by major railroads to other operators, railroad consolidations (such as the current Norfolk Southern and CSX proposals to acquire Conrail), business reengineering by railroad companies to cut costs, and new national labor agreements between the railroad industry and most of the major railroad unions are ongoing processes.

[9]U.S. Department of Labor, Bureau of Labor Statistics, "Multifactor Productivity in Railroad Transportation."
[10]Association of American Railroads, *Association of American Railroad Cost Indexes* (Washington, DC, September 1996 and prior issues).

Figure 4. Trends in Unadjusted and Adjusted Railroad Cost Adjustment Factors, 1987-1996



Source: Association of American Railroads, *Association of American Railroad Cost Indexes* (Washington, DC, September 1996 and prior issues).

Description of the PPI-Based Indexing Methodology

Model Objectives

The coal transportation rate indexing methodology is the mechanism by which base-year coal transportation rates for the NEMS forecasts are changed over time to capture transportation rate fluctuations resulting from changing railroad costs and other market conditions in the coal industry. The methodology is aimed at ensuring that projected changes in coal transportation rates conform to reasonable economic assumptions concerning railroad transportation costs, market competition, and rate-setting strategies. The methodology also aims at ensuring that the indexing of base-year coal transportation rates embodies the effects of railroad labor cost, fuel cost, equipment cost, and the incorporation of the price-dampening effects of productivity increases.

Base-year coal transportation rates are estimates of average transportation costs for each origin-destination pair. The costs are computed as the difference between the average delivered price of coal for a demand region (by end-use sector) and the average minemouth price for a supply region.[11]

Theoretical Approach and Rationale

The technical approach to the development of the coal transportation rate indexing methodology was to design an econometric model that conforms to economic theory and relevant market conditions within the coal transportation industry and that yields parameter estimates that are unbiased and statistically significant. The methodology should account for a significant amount of the variation in coal transportation rates over the historic period of study and should incorporate the measures of railroad productivity (operating efficiency).

Equation Specification

The equation below specifies that the average price that shippers pay to transport coal is a function of the average cost of labor in the railroad industry, the average price of fuel paid by the railroad industry, the average price of railroad equipment, and a railroad productivity trend. Specifically:

$$INDEXFACTOR = f(WAGE, PFUEL, PEQUIP, TREND) \quad (1)$$

where:

INDEXFACTOR is the value of the price index in year *t*. This variable equals the PPI for coal transportation divided by the chain-weighted implicit gross domestic product (GDP) deflator, and has a value of 1 in 1995 because it was rebased to 1995.

WAGE is the real wage cost index in year *t*.

PFUEL is the real price of distillate fuel in dollars per million British thermal units (Btu) to the industrial sector in year *t*.

PEQUIP is the producer price index for transportation equipment divided by the chain-weighted implicit GDP deflator, obtained from the NEMS Macroeconomic Activity Module.

TREND is the year *t*. Given the stable increase in productivity and the high correlation between time and productivity, time is a good proxy for productivity.

Historical data were available for each of the input variables for 1978 through 1995 (Table 1). A linear function of the regressors and a constant elasticity specification were considered in the mathematical formulation

[11]Delivered price data are from Energy Information Administration, Form EIA-3, "Quarterly Coal Consumption Report: Manufacturing Plants"; Form EIA-5, "Coke Plant Report: Quarterly"; FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants"; and U.S. Bureau of the Census, *Monthly Report EM-545*. Minemouth price data are from Energy Information Administration, Form EIA-7A, "Coal Production Report."

Table 1. Historical Data for Coal Transportation Rate Index Input Variables, 1978-1995

Year	Variable Name			
	WAGE	***PFUEL***	***PEQUIP***	***INDEXFACTOR***
1978	0.76	4.63	1.13	1.11
1979	0.77	5.87	1.13	1.20
1980	0.77	7.62	1.14	1.26
1981	0.80	8.20	1.19	1.32
1982	0.84	7.85	1.18	1.36
1983	0.89	7.23	1.17	1.32
1984	0.90	6.86	1.15	1.32
1985	0.88	6.36	1.14	1.28
1986	0.90	3.99	1.14	1.25
1987	0.92	4.30	1.13	1.21
1988	0.93	3.77	1.10	1.21
1989	0.93	4.26	1.09	1.18
1990	0.91	4.99	1.08	1.12
1991	0.93	4.29	1.08	1.08
1992	0.95	4.04	1.08	1.06
1993	0.93	3.89	1.08	1.04
1994	0.92	3.66	1.09	1.03
1995	0.94	3.58	1.08	1.00

Sources: The historical producer price index data for coal transportation were obtained from the U.S. Department of Labor, Bureau of Labor Statistics. The wage cost index was obtained from the Association of American Railroads. All other historical inputs were obtained from the NEMS Macroeconomic Activity Module.

of the model. Alternative formulations of both specifications were examined, including the effect of regulatory change in the railroad industry and interactions among the independent variables. Based on the results of this analysis, a log-linear function was chosen. Detailed regression statistics for the mathematical specification are described in Table 2. The log-linear specification has high explanatory power as indicated by the R^2 value and by a comparison of predicted versus actual values of the index factor. The log-linear equation explains variations in coal transportation rates over the sample period very well, and the parameter estimates are statistically significant as indicated by their t-statistic (Table 2).

Based on the regression results, the equation for forecasting coal transportation rate index factors is:

$$INDEXFACTOR = \psi \exp^{x} WAGE_t^{\beta_0} PFUEL_t^{\beta_1} PEQUIP_t^{\beta_2} \exp^{y} \quad , \qquad (2)$$

where:

$x = A + (k \cdot SE \cdot INITIALYEAR)$.

$A = 32.3303$.

$INITIALYEAR$ = first year of forecast.

β_0 = elasticity of *INDEXFACTOR* relative to *WAGE* = 1.08192.

β_1 = elasticity of *INDEXFACTOR* relative to *PFUEL* = 0.10022.

β_2 = elasticity of *INDEXFACTOR* relative to *PEQUIP* = 1.23010.

$y = (\beta_3 + k \cdot \mathrm{SE}) \cdot TREND$.

$\beta_3 = -0.016273$.

The parameter ψ is a benchmark factor that calibrates the function to the actual value of the index factor in 1995. A user-determined parameter (k) enables the user to incorporate judgment into the forecast to reflect

Table 2. Equation Results

Method of estimation: Ordinary Least Squares
Dependent variable: Ln(*INDEXFACTOR*)
Number of observations: 18
Mean of dependent variable: 0.166775
Standard deviation of dependent variable: 0.097467
Sum of squared residuals: 0.010247
Variance of residuals: 0.788218^{-3}
Standard error of regression: 0.028075
R^2: 0.936551
Adjusted R^2: 0.917028
Durbin-Watson statistic: 1.31884
Jarque-Bera normality test: 0.633885 [0.728]
F-statistic (zero slopes): 47.9723
Log of likelihood function: 41.6995

Variable	Estimated Coefficient	Standard Error	t-Statistic
A	32.3303	7.82517	4.13158
Ln(*WAGE*)	1.08192	0.204369	5.29396
Ln(*PFUEL*)	0.100220	0.043656	2.29565
Ln(*PEQUIP*)	1.23010	0.482512	2.54937
YEAR	-0.016273	0.391185^{-2}	-4.16000

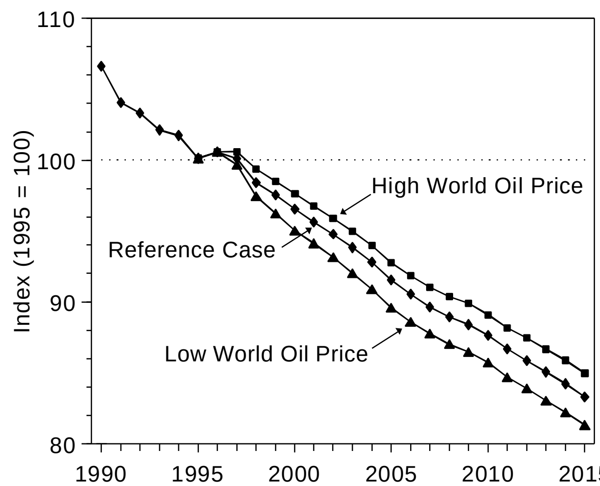
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

changes in expected saturation or slowing of productivity improvements. SE is the standard error of the estimate of β_3, and *INITIALYEAR* is 1995, the first year of the forecast. For example, a portion of the decline in transportation costs over the past 10 years may be the result of unique technology or regulatory changes. Accordingly, assuming a zero value for *k* might overstate the effect over the long term of projected productivity on the cost of transporting coal. The index factor that was used in the *AEO97* forecasts was calculated using k = -2. This moderates the effect of the estimated time trend. When k = -2, the effect of productivity over the forecast period is two standard deviations less than the estimate of β_3. If *k* is positive, the effect of productivity is greater than that implied by the estimate of β_3. Regression statistics are shown in Table 2. The value of β_3, the coefficient for TREND, is negative because when all the other input variables are accounted for, productivity gains in the railroad industry reduce the price of shipping coal.

Results

All the explanatory variables (or their proxies) used in the rate index equation are from other components of NEMS. The NEMS supplies the transportation rate index equation with a set of employee wage cost indexes, the industrial diesel fuel price in dollars per million Btu, and the PPI for transportation equipment. The equation uses these variables as input, along with a previously estimated time trend, and produces a forecast of coal transportation rate index factors for the forecast period. Figure 5 shows an output set of index factors produced by the methodology. The index factors in Figure 5 represent the *AEO97* reference case, high world oil price case, and low world oil price case forecasts.

Figure 5. *AEO97* Projected Coal Transportation Rate Indexes, 1996-2015



Source: AEO97 National Energy Modeling System, runs AEO97B.D100296K, LWOP97.D100696A, and HWOP97. D100296B.

The index factors were applied to the base-year coal transportation rates to produce a set of corresponding coal transportation rates for the *AEO97* forecast. The reference case index factors reduce transportation rates by 0.9 percent per year. In the high and low world oil price cases, the index factor decreases by 0.8 and 1.0 percent per year, respectively, over the 1995 to 2015 period.

The projected coal transportation rates reflect the historical trend of railroad productivity (operating efficiency), and the projected coal transportation rate changes are responsive to projected variations in the *AEO97* reference case fuel cost (No. 2 diesel fuel in the industrial sector), labor cost, and the PPI for transportation equipment. Coal transportation rates are projected to continue the decline reflected in the historic PPI for coal transportation, as competition among carriers and pressure from shippers for lower rates continue to force improvements in operating efficiency.

The delivered coal price to electricity generators in the reference case was projected to be $1.11 per million Btu in 2015. In the world oil price cases, variations in fuel cost yielded delivered coal prices to electricity generators that were 3.6 percent higher in the high oil price case ($1.15 per million Btu in 2015) and 2.7 percent lower in the low oil price case ($1.08 per million Btu in 2015). Approximately one-third of the price difference was attributable to changes in coal transportation costs.

Conclusion

The PPI-based coal transportation rate indexing methodology described here enhances the representation of various aspects of the railroad and coal industries relative to coal supply, demand, delivered price, transportation, and distribution patterns in the *AEO97* forecasts. The projected coal transportation rates reflect the influence of standard measures of railroad productivity, and the projected coal transportation rate changes are responsive to projected variations in the *AEO97* reference case fuel cost (No. 2 diesel fuel in the industrial sector). Coal transportation rates are projected to continue the decline reflected in the historic PPI for coal transportation, as competition among carriers and pressure from shippers for lower rates continue to force improvements in operating efficiency.

The methodology is integrated into the NEMS Coal Market Module to allow the impact of competition between coal and other fuels to influence coal transportation rates. The NEMS simulation enables rate changes to be influenced by economic factors such as fuel substitution, the tradeoff between purchase of low-sulfur coal and the use of scrubbers to meet emissions standards, and corresponding shifts in regional coal supply and distribution patterns.

Regional differences in coal transportation rates and coal production are expected to continue to exert an impact on coal distribution patterns over the forecast period. Western coal has already begun gaining shares in midwestern and southeastern coal markets, and export coal has begun movements on different domestic routes.[12] Shifts to supplies of western low-sulfur coal by some eastern seacoast consumers are expected to continue as coal transportation rates decrease, making it more economical on a per-ton-mile basis to ship western coal over long distances.

[12]Energy Information Administration, *Annual Energy Outlook 1997*, p. 69.

Annual Energy Outlook Forecast Evaluation

by
Susan H. Holte

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 1997 *to 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 four most recent* AEOs *to the evaluation, including 1996 as an additional historical year, and evaluating projections for the years 1991 through 1994, when available.*

Introduction

This paper presents an analysis of the forecast record of the *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 1996 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*.

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 relevancy to evolving energy issues and to update baseline data, parameters, and assumptions to the most recent historical data. 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.

The most recent examples of analytical studies are the service report *An Analysis of Carbon Mitigation Cases*,[4] prepared for the U.S. Environmental Protection Agency; a study on the costs and benefits of imported oil for the U.S. General Accounting Office;[5] an analysis of the environmental impacts of Federal Energy Regulatory Commission (FERC) Orders 888 and 889,[6] performed at the request of Senator James M. Jeffords, Vice Chairman of the Senate Subcommittee on Energy Production and Regulation; and a study of carbon reduction policies for the U.S. Department of Energy, Office of Policy and International Affairs.[7]

[1]Energy Information Administration, *Annual Energy Outlook 1997*, DOE/EIA-0383(97) (Washington, DC, December 1996) for the most recent *AEO*.

[2]Energy Information Administration, *Issues in Midterm Analysis and Forecasting 1996*, DOE/EIA-0607(96) (Washington, DC, September 1996).

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

[5]U.S. General Accounting Office, *Energy Security: Evaluating U.S. Vulnerability to Oil Shocks and Options for Mitigating Their Effects*, GAO/RCED-97-6 (Washington, DC, December 1996).

[6]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).

[7]Service report forthcoming.

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.

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 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, and various FERC orders. 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*)[8] presents 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 the *AEO*, which presents annual average projections.

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 understanding the reasons for differences between the projections and history is important both for users and for those persons responsible for the projections.

This paper presents projections for each *AEO* from 1982 to 1997.[9] The forecast horizon has expanded over the period examined in this paper; for example, the *Annual Energy Outlook 1982*[10] *(AEO82)* 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. A set of 16 key energy variables is used to provide a comprehensive picture of the projections. The projections in this analysis were produced by the models in use at the time. Prior to 1994, the Intermediate Future Forecasting System was the primary model for midterm projections. Also, in the past, different EIA analysts and a different process have formulated the projections.

[8]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, Third Quarter 1997*, DOE/EIA-0202(97/3Q) (Washington, DC, July 1997).

[9]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*.

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

Overview

Table 1 provides a summary of the average absolute forecast errors,[11] expressed as percentage differences from actual, for each of the major variables included in this analysis.[12] As the table 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[13] have been the least accurate.

Table 1. Average Absolute Percent Errors for *AEO* Forecasts, 1982-1997

Variable	Average Absolute Percent Error
Consumption	
Total Energy Consumption	1.6
Total Petroleum Consumption	2.8
Total Natural Gas Consumption	5.8
Total Coal Consumption	2.7
Total Electricity Sales	1.6
Production	
Crude Oil Production	4.2
Natural Gas Production	5.0
Coal Production	3.7
Imports and Exports	
Net Petroleum Imports	10.1
Net Natural Gas Imports	17.4
Net Coal Exports	22.1
Prices and Economic Variables	
World Oil Prices	53.1
Natural Gas Wellhead Prices	76.0
Coal Prices to Electric Utilities	34.8
Average Electricity Prices	11.0
Gross Domestic Product	5.0

AEO = *Annual Energy Outlook*.
Source: Tables 2 through 17.

Each of the consumption, production, and economic variables has been projected with an average absolute error of 5.8 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 1.6 percent. Average net import errors range from 10.1 percent for petroleum to 22.1 percent for coal. For prices, forecasting has proven to be a much greater challenge. Average errors for the world oil price, the price of coal to electric utilities, and the average natural gas wellhead price range from 34.8 to 76.0 percent over the period, with natural gas wellhead prices proving to have the highest average forecast error of the variables evaluated. Average electricity price projections, however, fared better, with a 11.0-percent average error.

While the following sections discuss the underlying results in some detail, 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 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; 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.[14] The overall average absolute percent error for the period examined here is 1.6 percent (Table 2),

[11]The average absolute errors displayed in Table 1 are the average absolute percent errors for each variable shown in Tables 2 through 17. This measure is computed as the mean, or average, of all the absolute values of the percentage errors shown for each *AEO*, for each year projected, for a given variable.

[12]The forecast evaluation in this paper is only for the *AEO* reference cases, with the exception of the final section on low world oil price 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.

[13]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.

[14]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 values for 1990 and later include dispersed renewables. Total energy consumption for 1990 and later in *AEO*s prior to the *AEO90* were adjusted to include dispersed renewables using adjustment factors derived from Energy Information Administration, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997), and *Monthly Energy Review*, DOE/EIA-0035(97/05) (Washington, DC, May 1997).

Table 2. Total Energy Consumption: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1996

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	Average Absolute Error
(Quadrillion Btu)													
AEO82	76.3	76.9	77.2	78.0	78.9	83.2							1.8
AEO83	75.2	76.8	78.3	79.6	80.7	84.5					89.8		1.1
AEO84	75.7	76.7	78.5	80.3	81.9	86.3					93.8		1.6
AEO85	74.8	75.8	77.1	78.4	79.5	83.2	84.2	85.5	86.3	87.0	88.0		1.2
AEO86		74.3	76.1	77.0	77.5	81.4	82.9	84.3	85.2	86.0	86.8	87.7	2.6
AEO87			76.2	77.2	78.8	82.7	83.9	85.6	86.8	87.8	88.7		1.3
AEO89				79.4	80.6	84.4	85.4	86.7	87.7	88.5	89.5	90.6	1.1
AEO90					80.8	85.4					91.9		0.9
AEO91						84.4	85.0	86.0	87.0	87.9	89.1	90.4	1.2
AEO92							84.7	87.0	88.0	89.2	90.5	91.4	1.0
AEO93								87.0	88.3	89.8	91.4	92.7	0.9
AEO94									88.0	89.5	90.7	91.7	0.8
AEO95										89.2	90.0	90.6	1.4
AEO96											90.6	91.3	1.4
AEO97												92.6	1.2
Actual Value	**74.0**	**74.3**	**76.9**	**80.2**	**81.3**	**84.1**	**84.0**	**85.5**	**87.3**	**89.2**	**90.9**	**93.8**	
Average Absolute Error	**1.5**	**1.8**	**0.8**	**1.7**	**1.6**	**1.2**	**0.7**	**0.9**	**0.8**	**1.1**	**1.5**	**2.8**	**1.4**
(Percent Error)													
AEO82	3.1	3.5	0.4	-2.8	-3.0	-1.0							2.3
AEO83	1.6	3.4	1.8	-0.8	-0.8	0.5					-1.2		1.4
AEO84	2.3	3.2	2.1	0.1	0.7	2.7					3.2		2.0
AEO85	1.1	2.0	0.3	-2.3	-2.2	-1.0	0.2	-0.1	-1.2	-2.5	-3.2		1.5
AEO86		0.0	-1.0	-4.0	-4.7	-3.2	-1.3	-1.5	-2.5	-3.6	-4.5	-6.5	3.0
AEO87			-0.9	-3.8	-3.1	-1.6	-0.1	0.1	-0.6	-1.6	-2.4		1.6
AEO89				-1.0	-0.9	0.4	1.6	1.4	0.4	-0.8	-1.5	-3.4	1.3
AEO90					-0.6	1.6					1.1		1.1
AEO91						0.4	1.1	0.6	-0.4	-1.5	-2.1	-3.6	1.4
AEO92							0.9	1.8	0.7	-0.1	-0.5	-2.5	1.1
AEO93								1.8	1.1	0.7	0.5	-1.2	1.0
AEO94									0.8	0.4	-0.2	-2.2	0.9
AEO95										0.0	-1.1	-3.5	1.5
AEO96											-0.4	-2.7	1.5
AEO97												-1.3	1.3
Average Absolute Percent Error	**2.1**	**2.4**	**1.1**	**2.1**	**2.0**	**1.4**	**0.9**	**1.0**	**1.0**	**1.2**	**1.7**	**3.0**	**1.6**

AEO = *Annual Energy Outlook*.

Btu = British thermal unit.

Note: Includes nonelectric renewables.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-97) (Washington, DC, April 1983 - December 1996).

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).

In terms of the *AEO* publications, the *Annual Energy Outlook 1986*[15] (*AEO86*) had the largest absolute and average absolute percent errors for total energy consumption, at 2.6 quadrillion Btu and 3.0 percent, respectively. There was a significant underestimate of energy consumption for most of the projected years in the *AEO86*, in part due to the high fossil fuel prices forecast for the publication, which was completed prior

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

to the 1986 collapse in oil prices and published early in 1987. Subsequent to the *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 errors for oil price forecasts in the *AEO86* were better than in the preceding *AEO*s. Price forecasts for some years in the *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 Outlook 1991*[16] (*AEO91*) projected much higher prices for 1991 and 1992.

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. By incorporating such standards, 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 averaged a 2.8-percent error 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, with an average error of 80.9 percent, the highest error for any year other than 1986 and 1995. In addition, the 1988 forecasts of economic growth 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,[17] and the *AEO86* had the highest average error for petroleum consumption at 5.3 percent. Projections of petroleum consumption were underestimated for all years in the *AEO86*, which was the last *AEO* completed before the oil price collapse. The projections for the years 1985 through 1987 in the *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 error of all of the petroleum forecasts evaluated. Residential and commercial consumption was projected to be more than 0.4 million barrels per day higher in 1985 than actual, 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. Both these numbers were reduced in the *Annual Energy Outlook 1983*[18] *(AEO83)* and are considerably more accurate. Although the *AEO82* projection for 1990 is precisely correct 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. Residential and commercial demand was better characterized by the following year. Also, between *AEO82* and *AEO83*, the role of natural gas in the electricity sector had been reevaluated. The projection of natural gas consumption by the electricity sector was up sharply in *AEO83*, and oil demand was greatly reduced.

Following *AEO82*, the projections of residential and commercial oil consumption remained rather close to actual, although the slight downturn in 1990 was missed. A general characterization of the forecasts is a tendency to underpredict energy consumption for several publications after the *Annual Energy Outlook 1984*[19] *(AEO84)*. At that time, there was an assumption that residential and commercial customers would purchase the most energy-efficient technologies, an assumption which resulted in overly optimistic efficiency improvements. The *Annual Energy Outlook 1985*[20] *(AEO85)* 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 underpredicted. The projected world oil prices were too high; and, in reaction

[16]Energy Information Administration, *Annual Energy Outlook 1991*, DOE/EIA-0383(91) (Washington, DC, March 1991).
[17]EIA published earlier forecasts in its *Annual Report to Congress*, which are not included in this report.
[18]Energy Information Administration, *Annual Energy Outlook 1983*, DOE/EIA-0383(83) (Washington, DC, May 1984).
[19]Energy Information Administration, *Annual Energy Outlook 1984*, DOE/EIA-0383(84) (Washington, DC, January 1985).
[20]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, 1985-1996

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	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	0.92
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	0.36
AEO90					17.24	17.41					18.21		0.33
AEO91						16.95	16.65	16.83	17.01	17.17	17.34	17.53	0.31
AEO92							16.74	17.07	17.37	17.59	17.80	17.86	0.13
AEO93								17.07	17.45	17.79	18.15	18.26	0.16
AEO94									17.67	17.99	18.20	18.42	0.34
AEO95										17.53	17.93	17.96	0.22
AEO96											17.78	17.88	0.21
AEO97												18.18	0.05
Actual Value	**15.73**	**16.28**	**16.67**	**17.28**	**17.33**	**16.99**	**16.71**	**17.03**	**17.24**	**17.72**	**17.72**	**18.23**	
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**	**0.43**	**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	-9.5	5.3
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	-1.0	2.1
AEO90					-0.5	2.5					2.8		1.9
AEO91						-0.2	-0.4	-1.2	-1.3	-3.1	-2.1	-3.9	1.7
AEO92							0.2	0.2	0.8	-0.7	0.5	-2.1	0.7
AEO93								0.2	1.2	0.4	2.4	0.1	0.9
AEO94									2.5	1.5	2.7	1.0	1.9
AEO95										-1.1	1.2	-1.5	1.3
AEO96											0.3	-1.9	1.1
AEO97												-0.3	0.3
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**	**2.4**	**2.8**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** 1985-1995—Energy Information Administration (EIA), *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). 1996—EIA, *Monthly Energy Review*, DOE/EIA-0035(97/05) (Washington, DC, May 1997). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-97) (Washington, DC, April 1983 - December 1996).

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 the *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 1987*[21] (*AEO87*), which contained the first set of projections after the oil price collapse in 1986.

Total Natural Gas Consumption

The overall error for natural gas consumption forecasts for this period is 5.8 percent (Table 4). Projections for

[21]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, 1985-1996

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	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	1.79
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	1.52
AEO90					18.34	18.66					20.69		0.47
AEO91						18.53	19.21	19.34	19.56	19.76	20.01	20.21	0.79
AEO92							18.79	19.36	19.84	20.08	20.53	20.68	0.63
AEO93								20.27	20.17	20.54	20.97	21.54	0.40
AEO94									19.87	20.21	20.64	20.99	0.69
AEO95										20.82	20.66	20.85	0.70
AEO96											21.32	21.64	0.27
AEO97												22.15	0.24
Actual Value	**17.28**	**16.22**	**17.21**	**18.03**	**18.80**	**18.72**	**19.04**	**19.54**	**20.28**	**20.71**	**21.58**	**21.91**	
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**	**1.38**	**1.15**
						(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	-17.7	8.8
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	-12.5	7.4
AEO90					-2.4	-0.3					-4.1		2.3
AEO91						-1.0	0.9	-1.0	-3.6	-4.6	-7.3	-7.8	3.7
AEO92							-1.3	-0.9	-2.2	-3.0	-4.9	-5.6	3.0
AEO93								3.7	-0.5	-0.8	-2.8	-1.7	1.9
AEO94									-2.0	-2.4	-4.4	-4.2	3.2
AEO95										0.5	-4.3	-4.8	3.2
AEO96											-1.2	-1.2	1.2
AEO97												1.1	1.1
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**	**6.3**	**5.8**

AEO = Annual Energy Outlook.

Note: *AEO82* projections were provided in British thermal units (Btu) and converted to cubic feet using a conversion factor of 1,030 Btu per cubic foot.

Sources: **Actual Values:** 1985-1995—Energy Information Administration (EIA), *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). 1996—EIA, *Monthly Energy Review*, DOE/EIA-0035(97/05) (Washington, DC, May 1997). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-97) (Washington, DC, April 1983 - December 1996).

1995 had the highest average percent error at 9.2 percent. For 1995, all of the *AEO*s underpredicted consumption by anywhere from 1 to 22 percent. For many of the statistics presented in this paper, 1995 and 1996 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 and were important causes for the underprediction of consumption in many years in the analysis period, as prices were overstated considerably in comparison to the actual prices. Consumption forecasts were also low because of the underestimation of the growth of gas demand in the industrial sector. The Power Plant and Industrial Fuel Use Act (FUA) also contributed to low estimates of gas consumption by industrial customers. Due to the perceived scarcity of natural gas, this legislation attempted to restrict gas use by large electric utility and industrial customers. Because of the number of exemptions granted to electric utilities, FUA had little impact on gas consumption forecasts by utilities, except in the *AEO82*; however, the legislation had 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 the *AEO83* through *AEO85* publications, natural gas consumption was generally underpredicted, 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, since prices were generally overestimated as well. Prior to 1995, 1986 was the year with the highest forecast error, at 7.0 percent. Except for *AEO82*, all the errors for 1986 were overpredictions. Although natural gas price projections for 1986 were high, oil price projections were also very high, and fuel switching from oil to gas was projected.

Among the *AEO*s, overall errors ranged from 1.2 to 9.4 percent, excepting the *Annual Energy Outlook 1997*[22] (*AEO97*) where there exists a single estimate of the most recent historical year that has a 1.1-percent error. The *AEO87* had the highest overall error, due mainly to its underestimate 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 underpredicted 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 with the *Annual Energy Outlook 1990*[23] (*AEO90*), with errors ranging from 1.1 to 3.7 percent. Natural gas price forecasts also improved with *AEO90*.

Total Coal Consumption

The forecasts for coal consumption have been stable and displayed fairly low average errors, in part due to the good record in forecasting electricity sales, for which coal is a major component in the production. The overall error for coal consumption is 2.7 percent (Table 5). As has generally been the case, forecasts for the years 1995 and 1996 tend to have the highest errors, averaging 4.4 and 5.0 percent, respectively. There was a strong tendency to overestimate in the earlier *AEO*s, particularly the *AEO84*, whose forecast was 15.4 percent over actual 1995 coal 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.

Because of the high 1995 projection, the *AEO84* had the highest error for coal consumption of the *AEO*s examined, at 5.4 percent. All the other *AEO*s, with the exception of *AEO97*, had average errors no higher than 4.5 percent. At the time the projections for the *AEO97* were finalized, only partial data for 1996 were available. Due to an increase in natural gas prices in 1996 and, consequently, a drop in gas consumption by electricity generators, there was a notable surge in coal consumption by generators in 1996, which caused some of the larger errors for that year in most *AEO*s.

Total Electricity Sales

The average error for projections of electricity sales is 1.6 percent over the period studied (Table 6). The highest errors are 2.2 and 2.3 percent for 1995 and 1996, respectively. Electricity sales for all years were overpredicted in *AEO82*, and, with the exception of *AEO87*, all subsequent *AEO*s through the *AEO90* tended to underpredict the earlier years and overpredict the later years. In earlier *AEO*s, overpredictions 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 the *AEO91*, electricity sales have been underpredicted in most years, due primarily to optimistic estimates of efficiency improvements, coupled with continued growth in new uses for electricity that was not captured in the projections. In addition, 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.

[22]Energy Information Administration, *Annual Energy Outlook 1997*, DOE/EIA-0383(97) (Washington, DC, December 1996).
[23]Energy Information Administration, *Annual Energy Outlook 1990*, DOE/EIA-0383(90) (Washington, DC, January 1990).

Table 5. Total Coal Consumption: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1996

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	Average Absolute Error
						(Million Short Tons)							
AEO82	805	825	843	868	896	936							17
AEO83	807	831	848	870	899	928					1061		29
AEO84	843	848	866	889	919	958					1110		49
AEO85	818	833	842	853	867	891	918	943	970	989	1008		24
AEO86		813	831	860	870	888	919	945	972	995	1021	1038	27
AEO87			837	837	854	879	896	912	932	954	975		16
AEO89				872	882	894	903	927	947	965	987	990	13
AEO90					884	893					984		10
AEO91						893	902	918	932	943	948	962	15
AEO92							905	934	919	925	934	944	31
AEO93								929	931	940	947	958	22
AEO94									920	928	933	938	36
AEO95										935	940	941	34
AEO96											937	942	45
AEO97												948	58
Actual Value	**818**	**804**	**837**	**884**	**890**	**896**	**888**	**907**	**944**	**951**	**962**	**1006**	
Average Absolute Error	**12**	**26**	**10**	**21**	**17**	**19**	**19**	**23**	**18**	**20**	**42**	**51**	**25**
						(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	4.0	2.8	4.0	4.8		2.7
AEO86		1.1	-0.7	-2.7	-2.2	-0.9	3.5	4.2	3.0	4.6	6.1	3.2	2.9
AEO87			0.0	-5.3	-4.0	-1.9	0.9	0.6	-1.3	0.3	1.4		1.7
AEO89				-1.4	-0.9	-0.2	1.7	2.2	0.3	1.5	2.6	-1.6	1.4
AEO90					-0.7	-0.3					2.3		1.1
AEO91						-0.3	1.6	1.2	-1.3	-0.8	-1.5	-4.4	1.6
AEO92							1.9	3.0	-2.6	-2.7	-2.9	-6.2	3.2
AEO93								2.4	-1.4	-1.2	-1.6	-4.8	2.3
AEO94									-2.5	-2.4	-3.0	-6.8	3.7
AEO95										-1.7	-2.3	-6.5	3.5
AEO96											-2.6	-6.4	4.5
AEO97												-5.8	5.8
Average Absolute Percent Error . . .	**1.5**	**3.2**	**1.1**	**2.4**	**1.9**	**2.1**	**2.2**	**2.5**	**1.9**	**2.1**	**4.4**	**5.0**	**2.7**

AEO = *Annual Energy Outlook*.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-97) (Washington, DC, April 1983 - December 1996).

In terms of the *AEO* publications, the highest average error was that of the *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 in this decade. The error in electricity sales was more than halved by the *AEO83*.

Table 6. Total Electricity Sales: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1996

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	Average Absolute Error
(Billion Kilowatthours)													
AEO82	2364	2454	2534	2626	2708	2811							68
AEO83	2318	2395	2476	2565	2650	2739					3153		33
AEO84	2321	2376	2461	2551	2637	2738					3182		35
AEO85	2317	2360	2427	2491	2570	2651	2730	2808	2879	2949	3026		36
AEO86		2363	2416	2479	2533	2608	2706	2798	2883	2966	3048	3116	52
AEO87			2460	2494	2555	2622	2683	2748	2823	2902	2977		52
AEO89				2556	2619	2689	2760	2835	2917	2994	3072	3156	44
AEO90					2612	2689					3083		43
AEO91						2700	2762	2806	2855	2904	2959	3022	30
AEO92							2746	2845	2858	2913	2975	3030	36
AEO93								2803	2840	2893	2946	2998	51
AEO94									2843	2891	2928	2962	68
AEO95										2951	2967	2983	55
AEO96											2973	2998	64
AEO97												3075	10
Actual Value	**2324**	**2369**	**2457**	**2578**	**2647**	**2713**	**2762**	**2763**	**2861**	**2935**	**3013**	**3085**	
Average Absolute Error	**14**	**27**	**29**	**54**	**53**	**52**	**31**	**47**	**23**	**32**	**66**	**70**	**45**
(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	1.0	1.9
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	2.3	1.5
AEO90					-1.3	-0.9					2.3		1.5
AEO91						-0.5	0.0	1.6	-0.2	-1.1	-1.8	-2.0	1.0
AEO92							-0.6	3.0	-0.1	-0.7	-1.3	-1.8	1.2
AEO93								1.4	-0.7	-1.4	-2.2	-2.8	1.7
AEO94									-0.6	-1.5	-2.8	-4.0	2.2
AEO95										0.5	-1.5	-3.3	1.8
AEO96											-1.3	-2.8	2.1
AEO97												-0.3	0.3
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**	**2.3**	**1.6**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** 1985-1995—Energy Information Administration (EIA), *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). 1996—EIA, *Monthly Energy Review*, DOE/EIA-0035(97/05) (Washington, DC, May 1997). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-97) (Washington, DC, April 1983 - December 1996).

Energy Production

Crude Oil Production

Crude oil production forecasts have been reasonably accurate, with an overall average error of 4.2 percent over the period evaluated (Table 7). The largest error for any given year was 1989, with an average error of 7.8 percent and all *AEO*s overestimating actual production for that year. Since 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 in most years, particularly for 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 the *AEO85*, EIA's price forecasts were either very close to, or significantly

Table 7. Crude Oil Production: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1996

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	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	0.38
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	0.28
AEO90					7.67	7.37					6.40		0.08
AEO91						7.23	6.98	7.10	7.11	7.01	6.79	6.48	0.21
AEO92							7.37	7.17	6.99	6.89	6.68	6.45	0.09
AEO93								7.20	6.94	6.79	6.52	6.22	0.11
AEO94									6.87	6.50	6.18	5.92	0.28
AEO95										6.58	6.32	6.04	0.25
AEO96											6.54	6.33	0.08
AEO97												6.47	0.00
Actual Value	**8.97**	**8.68**	**8.35**	**8.14**	**7.61**	**7.36**	**7.42**	**7.17**	**6.85**	**6.66**	**6.56**	**6.47**	
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**	**0.28**	**0.30**
						(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	-10.4	5.4
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	-6.5	4.0
AEO90					0.7	0.2					-2.4		1.1
AEO91						-1.7	-5.9	-1.0	3.8	5.2	3.5	0.1	3.0
AEO92							-0.6	0.0	2.1	3.4	1.8	-0.3	1.4
AEO93								0.4	1.4	1.9	-0.6	-3.9	1.6
AEO94									0.3	-2.4	-5.8	-8.5	4.3
AEO95										-1.2	-3.7	-6.7	3.8
AEO96											-0.3	-2.2	1.2
AEO97												0.0	0.0
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**	**4.3**	**4.2**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** 1985-1995—Energy Information Administration (EIA), *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). 1996—EIA, *Monthly Energy Review*, DOE/EIA-0035(97/05) (Washington, DC, May 1997). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-97) (Washington, DC, April 1983 - December 1996).

under, the actual 1989 price, with a consequent improvement in production projections.

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

Following the oil price collapse of 1986, there were about as many underpredictions and overpredictions of crude oil production. As price projections have been reduced over time, the forecasts have captured the impacts of technological improvement in the oil industry, preventing the production forecasts from falling as precipitously as the price projections.

Natural Gas Production

The overall average error for natural gas production forecasts is 5.0 percent (Table 8), slightly lower than the 5.8-percent average error for consumption forecasts. Unlike crude oil, most demand for natural gas is met by domestic production; thus, natural gas production tends to follow the projections for consumption. Forecasts for 1994 display the highest average 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 the *AEO83*, the first *AEO* to forecast 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.

Table 8. Natural Gas Production: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1996

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	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	1.06
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	0.94
AEO90					16.91	17.25					18.84		0.40
AEO91						17.40	17.48	18.11	18.22	18.15	18.22	18.39	0.39
AEO92							17.43	17.69	17.95	18.00	18.29	18.27	0.41
AEO93								18.47	18.05	18.16	18.45	18.90	0.32
AEO94									17.71	17.68	17.84	18.12	0.80
AEO95										18.28	17.98	17.92	0.76
AEO96											18.90	19.15	0.21
AEO97												19.10	0.08
Actual Value	**16.45**	**16.06**	**16.62**	**17.10**	**17.31**	**17.81**	**17.70**	**17.84**	**18.10**	**18.82**	**18.60**	**19.03**	
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**	**0.86**	**0.89**
						(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	-13.8	5.8
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	-7.1	5.2
AEO90					-2.3	-3.1					1.3		2.2
AEO91						-2.3	-1.2	1.5	0.7	-3.6	-2.0	-3.3	2.1
AEO92							-1.5	-0.8	-0.8	-4.4	-1.7	-4.0	2.2
AEO93								3.5	-0.3	-3.5	-0.8	-0.7	1.8
AEO94									-2.2	-6.1	-4.1	-4.8	4.3
AEO95										-2.9	-3.3	-5.8	4.0
AEO96											1.6	0.7	1.1
AEO97												0.4	0.4
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**	**4.5**	**5.0**

AEO = *Annual Energy Outlook.*

Note: *AEO82* projections were provided in British thermal units (Btu) and converted to cubic feet using a conversion factor of 1,030 Btu per cubic foot.

Sources: **Actual Values:** 1985-1995—Energy Information Administration (EIA), *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). 1996—EIA, *Monthly Energy Review*, DOE/EIA-0035(97/05) (Washington, DC, May 1997). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-97) (Washington, DC, April 1983 - December 1996).

The *AEO82* underpredicted gas production in all years and had an 11.7-percent average error. The *AEO87* had the second highest error at 7.7 percent, and for all others the average error rate has been 6.2 percent (for *AEO83*) or less. The errors in production forecasts have resulted primarily from the low consumption forecasts, coupled with high price forecasts. In general, the *AEO*s have understated production, with the exception of the years prior to 1990 in the *AEO84* and *AEO85*, and most of the errors have been very 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 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 lowered the cost of gas exploration and production and expanded the estimates of the resource base. Beginning with the *AEO90*, the forecasts of both production and price vastly improved.

Coal Production

Similarly to coal consumption, coal production forecasts have shown a good record, with an overall average error of 3.7 percent (Table 9). Like natural gas, the forecasts for coal production have generally followed those for consumption, 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 coal exports, especially for the years 1993 through 1995, as is discussed below.

The year 1993 shows the highest average error for coal production, at 9.7 percent. In 1993, there was a strike by coal producers that led to sharply reduced production. Consequently, all *AEO*s produced prior to the strike show high forecast errors for 1993. The second highest average 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 overprediction of coal consumption, particularly in the *AEO83* and *AEO84*, and the higher-than-realized coal export projections in *AEO83* through *AEO86*, discussed below. The forecasts for other years average much closer to actual, with errors ranging from 1 to 4 percent. The *AEO* publications display little variation in the overall average error of each, with the *AEO84* showing the highest average error of 5 percent, mainly because of its very high projection for 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

Since domestic production of petroleum is insufficient to meet demand, imports make up the difference between demand and supply.[24] The average error for net petroleum imports over the period studied was 10.1 percent (Table 10). The forecast year with the highest average 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 underpredict imports for the mid-1980s, because of the underprediction of consumption and the overestimates of production. Except for the *AEO83* and *AEO85*, this tendency was generally reversed for projections of the 1990s, with significant overestimates of net petroleum imports for many years in the *AEO84* through the *Annual Energy Outlook 1995*[25] (*AEO95*). While 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 errors for forecasts of net petroleum imports. The *AEO82* tended to strongly overpredict 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, the *AEO83*, *AEO84*, and *AEO85* strongly underestimated imports in many years, as did the *AEO86* for the late 1980s. Later reports tended to overestimate imports due to underestimates of production.

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

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

Table 9. Coal Production: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1996

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	Average Absolute Error
(Million Short Tons)													
AEO82	914	939	963	995	1031	1080							45
AEO83	900	926	947	974	1010	1045					1191		44
AEO84	899	921	948	974	1010	1057					1221		49
AEO85	886	909	930	940	958	985	1015	1041	1072	1094	1116		40
AEO86		890	920	954	962	983	1017	1044	1073	1097	1126	1142	46
AEO87			917	914	932	962	978	996	1020	1043	1068		33
AEO89				941	946	977	990	1018	1039	1058	1082	1084	35
AEO90					973	987					1085		34
AEO91						1035	1002	1016	1031	1043	1054	1065	22
AEO92							1004	1040	1019	1034	1052	1064	25
AEO93								1039	1043	1054	1065	1076	42
AEO94									999	1021	1041	1051	20
AEO95										1006	1010	1011	32
AEO96											1037	1044	9
AEO97												1028	29
Actual Value	**884**	**890**	**919**	**950**	**981**	**1029**	**996**	**998**	**945**	**1034**	**1033**	**1057**	
Average Absolute Error	**16**	**27**	**19**	**22**	**30**	**39**	**13**	**30**	**92**	**25**	**59**	**27**	**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	8.0	4.6
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	2.6	3.5
AEO90					-0.8	-4.1					5.0		3.3
AEO91						0.6	0.6	1.8	9.1	0.9	2.0	0.8	2.2
AEO92							0.8	4.2	7.8	0.0	1.8	0.7	2.6
AEO93								4.1	10.4	1.9	3.1	1.8	4.3
AEO94									5.7	-1.3	0.8	-0.6	2.1
AEO95										-2.7	-2.2	-4.4	3.1
AEO96											0.4	-1.2	0.8
AEO97												-2.7	2.7
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**	**2.5**	**3.7**

AEO = *Annual Energy Outlook.*

Sources: **Actual Values:** 1985-1995—Energy Information Administration (EIA), *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). 1996—EIA, *Monthly Energy Review*, DOE/EIA-0035(97/05) (Washington, DC, May 1997). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-97) (Washington, DC, April 1983 - December 1996).

Net Natural Gas Imports

Net natural gas imports play a small, but important, supplementary role in meeting natural gas demand. The overall average error for the period covered in this study is 17.4 percent, with the largest 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 the *AEO86* and *AEO87* reversed the pattern with underestimates. *AEO85* also showed high overestimates through 1992

Table 10. Net Petroleum Imports: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1996

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	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	0.51
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	0.97
AEO90					7.20	7.61					9.13		0.56
AEO91						7.28	7.25	7.34	7.48	7.72	8.10	8.57	0.28
AEO92							6.86	7.42	7.88	8.16	8.55	8.80	0.35
AEO93								7.25	8.01	8.49	9.06	9.38	0.65
AEO94									8.04	8.77	9.21	9.60	0.91
AEO95										8.09	8.65	8.99	0.46
AEO96											8.25	8.51	0.23
AEO97												8.49	0.07
Actual Value	**4.29**	**5.44**	**5.91**	**6.59**	**7.20**	**7.16**	**6.63**	**6.94**	**7.62**	**8.05**	**7.89**	**8.42**	
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**	**0.52**	**0.68**
						(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	0.6	7.4
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	14.0	13.0
AEO90					0.0	6.3					15.7		7.3
AEO91						1.7	9.4	5.8	-1.8	-4.1	2.7	1.8	3.9
AEO92							3.5	6.9	3.4	1.4	8.4	4.5	4.7
AEO93								4.5	5.1	5.5	14.8	11.4	8.3
AEO94									5.5	8.9	16.7	14.0	11.3
AEO95										0.5	9.6	6.8	5.6
AEO96											4.6	1.1	2.8
AEO97												0.8	0.8
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**	**6.1**	**10.1**

AEO = *Annual Energy Outlook*.

Sources: **Actual Values:** 1985-1995—Energy Information Administration (EIA), *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). 1996—EIA, *Monthly Energy Review*, DOE/EIA-0035(97/05) (Washington, DC, May 1997). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-97) (Washington, DC, April 1983 - December 1996).

and underestimates for later years. Most *AEO*s tended to underestimate imports, with errors as high as 54.2 percent for the *AEO83* in 1995.

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 1995 forecasts. Since the *AEO86* forecast, there has been a greater tendency to underpredict. Since the *Annual Energy Outlook 1993*[26] (*AEO93*), the projections have been much closer to actual, with an error of 5.7 percent or less.

[26]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, 1985-1996

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	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	0.50
AEO87			0.84	0.89	1.07	1.16	1.26	1.36	1.46	1.65	1.75		0.48
AEO89				1.15	1.32	1.44	1.52	1.61	1.70	1.79	1.87	1.98	0.37
AEO90					1.26	1.43					2.07		0.22
AEO91						1.36	1.53	1.70	1.82	2.11	2.30	2.33	0.28
AEO92							1.48	1.62	1.88	2.08	2.25	2.41	0.32
AEO93								1.79	2.08	2.35	2.49	2.61	0.14
AEO94									2.02	2.40	2.66	2.74	0.08
AEO95										2.46	2.54	2.80	0.08
AEO96											2.56	2.75	0.08
AEO97												2.82	0.11
Actual Value	**0.89**	**0.69**	**0.94**	**1.22**	**1.28**	**1.45**	**1.64**	**1.92**	**2.21**	**2.46**	**2.69**	**2.72**	
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**	**0.28**	**0.30**
(Percent Error)													
AEO82	33.1	72.7	26.7	-2.5	-6.7	-17.7							26.6
AEO83	20.8	68.4	31.0	0.8	-3.5	-14.9					-54.2		27.7
AEO84	10.7	52.4	23.5	4.1	12.2	8.6					-21.5		19.0
AEO85	5.1	45.1	26.7	18.9	23.9	28.6	18.0	7.2	-1.8	-5.8	-9.2		17.3
AEO86		7.4	-6.3	-49.2	-19.2	-27.4	-22.7	-27.6	-33.5	-32.6	-33.4	-27.8	26.1
AEO87			-10.5	-27.0	-16.1	-19.8	-23.4	-29.2	-33.9	-33.0	-34.9		25.3
AEO89				-5.7	3.5	-0.4	-7.5	-16.2	-23.1	-27.3	-30.4	-27.1	15.7
AEO90					-1.2	-1.1					-23.0		8.4
AEO91						-5.9	-6.9	-11.5	-17.6	-14.3	-14.4	-14.2	12.1
AEO92							-10.0	-15.7	-14.9	-15.5	-16.3	-11.2	13.9
AEO93								-6.8	-5.9	-4.5	-7.3	-3.9	5.7
AEO94									-8.6	-2.5	-1.0	0.9	3.3
AEO95										-0.1	-5.5	3.1	2.9
AEO96											-4.7	1.3	3.0
AEO97												3.9	3.9
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**	**10.4**	**17.4**

AEO = Annual Energy Outlook.

Note: *AEO82* projections were provided in British thermal units (Btu) and converted to cubic feet using a conversion factor of 1,030 Btu per cubic foot.

Sources: **Actual Values:** 1985-1995—Energy Information Administration (EIA), *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). 1996—EIA, *Monthly Energy Review*, DOE/EIA-0035(97/05) (Washington, DC, May 1997). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-97) (Washington, DC, April 1983 - December 1996).

Net Coal Exports

The errors in projections for net coal exports have averaged 22.1 percent over the period of this study (Table 12). The forecast year 1994 had by far the highest average errors, followed closely by 1993, with all of the *AEO*s, except the *AEO95*, overstating coal exports by anywhere from about 30 to 77 percent. There were also high average errors for 1993 and 1995, but the record for other forecast years was better, with only an 8.4-percent average forecast error for 1992. For the *AEO84* through the *Annual Energy Outlook 1994*[27] (*AEO94*), coal exports were generally underestimated through 1992 and overestimated in later years. The most recent

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

Table 12. Net Coal Exports: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1996

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	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	14
AEO87			76	72	73	76	77	79	82	83	86		18
AEO89				84	80	82	83	85	87	88	90	93	16
AEO90					95	92					99		11
AEO91						105	96	96	97	100	104	100	17
AEO92							98	99	103	109	116	117	26
AEO93								108	111	113	117	118	35
AEO94									79	93	108	110	24
AEO95										57	66	69	12
AEO96											71	76	9
AEO97												82	1
Actual Value	**91**	**83**	**78**	**93**	**98**	**103**	**106**	**99**	**67**	**64**	**81**	**83**	
Average Absolute Error	**13**	**9**	**12**	**13**	**15**	**16**	**17**	**8**	**27**	**31**	**21**	**18**	**18**
						(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	18.4
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	19.4
AEO90					-3.1	-10.7					22.2		12.0
AEO91						1.9	-9.4	-3.0	44.8	56.3	28.4	20.5	23.5
AEO92							-7.5	0.0	53.7	70.3	43.2	41.0	36.0
AEO93								9.1	65.7	76.6	44.4	42.2	47.6
AEO94									17.9	45.3	33.3	32.5	32.3
AEO95										-10.9	-18.5	-16.9	15.4
AEO96											-12.3	-8.4	10.4
AEO97												-1.2	1.2
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**	**22.1**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** 1985-1995—Energy Information Administration (EIA), *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). 1996—EIA, *Monthly Energy Review*, DOE/EIA-0035(97/05) (Washington, DC, May 1997). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-97) (Washington, DC, April 1983 - December 1996).

*AEO*s underestimated exports by a range of 1 to 19 percent.

The *AEO82* overestimated future coal exports by an average 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. The *AEO83*, by contrast, had a much more realistic view of future coal exports and, with the exception of 1995, had a very good record. *AEO83*, the *Annual Energy Outlook 1996*[28] (*AEO96*), and *AEO97* were the closest of all the *AEO*s with respect to projected coal exports. Projections for 1993 through 1996 in the *AEO91* through the *AEO94*

[28]Energy Information Administration, *Annual Energy Outlook 1996*, DOE/EIA-0383(96) (Washington, DC, January 1996).

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, since 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. The latest *AEO*s appear to be overcompensating for this trend.

Energy Prices and Economic Growth[29]

World Oil Prices

World oil prices have the second highest average forecast errors of all of those evaluated in this paper, with natural gas prices at the wellhead being the highest. Overall, the average percent error for world oil price forecasts has been 53.1 percent (Table 13). However, the earlier *AEO*s had a much higher average error, and the publications after the *AEO86* showed considerable improvement, with the exception of *AEO91*, which was affected by the Iraqi invasion of Kuwait. Similarly, the year with the highest average forecast errors was 1995, followed closely by 1986, with very high 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 the *AEO83* was nearly $75 per barrel, compared to an actual price of $17.14 per barrel.

For many of the variables examined in this paper, the highest average errors are seen for the year 1995. As mentioned above, the 1995 projections include those made furthest in the past—up to 12 years earlier. In addition, projections for 1991 through 1994 are missing for the earliest publications, so that 1995 appears to be more of an outlier.

Although the forecasts appearing in the earlier *AEO*s were almost uniformly too high, from the *AEO86* on there were several instances of underprediction. These included the 1987 and 1990 forecasts appearing in the *AEO86* and *AEO87*, the forecasts for 1989 through 1991 appearing in the *Annual Energy Outlook 1989*[30] (*AEO89*) 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 average forecast errors until the *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 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 forecast errors in the *AEO*s, with an overall average error of 76.0 percent (Table 14). Occasionally, the gas price has been underestimated, but these are all estimates of near-term prices. Similar to the world oil price, forecasts for natural gas prices were highest in the earlier *AEO*s, as 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 the higher world oil prices.

The year 1995 had the highest average forecast error; with the exception of the *AEO96*, which was essentially estimating the recent historical year for 1995, the smallest error for 1995 was 28.6 percent in the *AEO95*. The year with the lowest average error was 1985, with an average 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 for 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.

[29]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.

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

Table 13. World Oil Prices: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1996

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	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					74.32		22.19
AEO84	28.92	28.67	29.56	31.76	34.27	37.00					56.71		16.60
AEO85	27.00	25.70	24.38	25.26	28.60	32.23	34.75	36.99	37.95	40.14	41.17		14.09
AEO86		14.57	15.89	17.28	18.91	20.72	22.20	24.74	28.25	32.02	35.52	38.48	7.49
AEO87			18.11	17.41	19.01	20.06	20.97	21.54	23.17	25.71	29.00		4.47
AEO89				14.70	15.00	16.31	17.52	18.47	20.38	23.03	25.74	28.67	4.29
AEO90					17.70	17.53					24.47		3.98
AEO91						22.00	24.95	25.64	26.31	26.90	27.59	28.13	7.64
AEO92							19.13	20.19	20.72	22.19	23.91	25.55	4.24
AEO93								18.90	20.09	20.92	22.01	22.89	3.45
AEO94									17.12	17.24	18.28	19.37	1.26
AEO95										15.23	17.21	18.07	0.95
AEO96											17.24	17.76	1.46
AEO97												19.90	0.67
Actual Value	**26.99**	**14.00**	**18.13**	**14.56**	**18.08**	**21.76**	**18.70**	**18.20**	**16.14**	**15.51**	**17.14**	**20.57**	
Average Absolute Error	**1.22**	**11.92**	**8.62**	**11.78**	**10.36**	**10.09**	**4.95**	**5.58**	**8.11**	**9.37**	**14.64**	**5.34**	**9.11**
						(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					333.6		128.8
AEO84	7.2	104.8	63.1	118.2	89.6	70.0					230.8		97.7
AEO85	0.0	83.6	34.5	73.5	58.2	48.1	85.8	103.2	135.1	158.8	140.2		83.7
AEO86		4.1	-12.4	18.7	4.6	-4.8	18.7	35.9	75.0	106.4	107.3	87.1	43.2
AEO87			-0.1	19.6	5.1	-7.8	12.1	18.4	43.6	65.8	69.2		26.9
AEO89				1.0	-17.0	-25.1	-6.3	1.5	26.3	48.5	50.2	39.4	23.9
AEO90					-2.1	-19.4					42.8		21.4
AEO91						1.1	33.4	40.9	63.0	73.4	61.0	36.7	44.2
AEO92							2.3	10.9	28.4	43.1	39.5	24.2	24.7
AEO93								3.8	24.5	34.9	28.4	11.3	20.6
AEO94									6.1	11.1	6.7	-5.8	7.4
AEO95										-1.8	0.4	-12.2	4.8
AEO96											0.6	-13.7	7.1
AEO97												-3.3	3.3
Average Absolute Percent Error	**4.5**	**85.1**	**47.6**	**80.9**	**57.3**	**46.4**	**26.5**	**30.7**	**50.2**	**60.4**	**85.4**	**25.9**	**53.1**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** 1985-1995—Energy Information Administration (EIA), *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). 1996—EIA, *Monthly Energy Review*, DOE/EIA-0035(97/05) (Washington, DC, May 1997). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-97) (Washington, DC, April 1983 - December 1996).

Nevertheless, each *AEO* has tended to predict rising prices over time, either because of the assumption in the earlier *AEO*s that long-term, high-priced contracts would continue or because the depletion effects associated with rising consumption were expected to overcome technological improvement 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

Table 14. Natural Gas Wellhead Prices: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1996

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	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					9.32		2.57
AEO84	2.76	2.82	3.07	3.39	3.81	4.34					7.16		2.08
AEO85	2.60	2.59	2.61	2.62	2.84	3.20	3.62	4.07	4.51	4.99	5.53		1.74
AEO86		1.73	1.96	2.29	2.55	2.82	3.14	3.64	4.12	4.65	5.25	5.83	1.69
AEO87			1.83	1.96	2.12	2.30	2.49	2.70	2.98	3.28	3.69		0.86
AEO89				1.62	1.71	1.90	2.10	2.49	2.86	3.18	3.50	4.10	0.83
AEO90					1.78	1.89					2.70		0.47
AEO91						1.77	1.91	2.12	2.29	2.38	2.44	2.48	0.37
AEO92							1.69	1.86	2.04	2.14	2.32	2.44	0.24
AEO93								1.85	1.92	2.06	2.26	2.36	0.25
AEO94									1.99	2.13	2.27	2.40	0.30
AEO95										1.89	1.99	1.94	0.27
AEO96											1.64	1.75	0.30
AEO97												2.02	0.23
Actual Value	**2.51**	**1.94**	**1.67**	**1.69**	**1.69**	**1.71**	**1.64**	**1.74**	**2.04**	**1.85**	**1.55**	**2.25**	
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**	**0.80**	**1.31**
(Percent Error)													
AEO82	65.2	163.1	260.5	287.8	304.0	315.8							232.7
AEO83	14.5	53.5	94.7	113.3	142.5	171.1					501.1		155.8
AEO84	9.9	45.6	83.6	100.7	125.2	153.9					361.9		125.8
AEO85	3.6	33.5	56.1	55.3	67.9	87.1	121.0	133.8	121.3	169.8	256.8		100.6
AEO86		-10.8	17.3	35.3	50.8	65.0	91.4	108.9	102.2	151.2	238.5	158.9	93.7
AEO87			9.6	15.9	25.2	34.4	52.1	54.9	45.9	77.4	138.1		50.4
AEO89				-4.1	1.1	11.3	28.2	42.8	40.2	71.9	125.8	82.3	45.3
AEO90					5.3	10.5					74.1		30.0
AEO91						3.5	16.6	21.6	12.3	28.4	57.2	10.4	21.4
AEO92							3.3	6.8	-0.1	15.7	49.8	8.3	14.0
AEO93								6.3	-5.9	11.3	45.5	4.7	14.8
AEO94									-2.4	15.1	46.5	6.8	17.7
AEO95										2.2	28.6	-14.0	14.9
AEO96											5.9	-22.4	14.1
AEO97												-10.3	10.3
Average Absolute Percent Error	**23.3**	**61.3**	**87.0**	**87.5**	**90.2**	**94.7**	**52.1**	**53.6**	**41.3**	**60.3**	**148.4**	**35.4**	**76.0**

AEO = Annual Energy Outlook.

Note: *AEO82* projections were provided in British thermal units (Btu) and converted to cubic feet using a conversion factor of 1,030 Btu per cubic foot.

Sources: **Actual Values:** 1985-1995—Energy Information Administration (EIA), *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). 1996—EIA, *Monthly Energy Review*, DOE/EIA-0035(97/05) (Washington, DC, May 1997). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-97) (Washington, DC, April 1983 - December 1996).

natural gas fell, although not as much as the price of oil.

- Estimates of the recoverable resource base rose and estimates of exploration and production costs fell over time, in contrast to the assumptions in the earlier forecasts. Since the models use this information as an input, higher assumed levels of recoverable resources and lower assumed costs would have resulted in forecasts characterized by more gas available for production at lower prices. More recent *AEO*s allow for increases in the resource base and decreases in costs due to technology improvements.

- 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, lowering end-use prices and stimulating additional price competition at the wellhead as well.

Thus, while the forecasts improved with additional information, they continued to be affected by the impacts of wellhead price deregulation and the changing competitive structure of the industry, as the projections assumed existing regulations, and by overestimates of the impacts of reserve depletion relative to technology improvements.

It is worth noting that much of the domestic production of natural gas is as a coproduct of the crude oil extraction process, which means that, as crude oil production rises due to higher oil prices, there may be a depressing effect on the wellhead price of gas. This effect has added to the complexity of forecasting natural gas prices.

Coal Prices to Electric Utilities

While better than those of oil and gas, forecasts of coal prices to electric utilities still show an average error of 34.8 percent over the period studied (Table 15). All forecasts were overstated. The forecasts for 1995 had the highest average error of 57.5 percent. There was, however, significant improvement in the 1995 forecast over time, with the error improving from 137.9 percent in the *AEO83* to 10.6 percent in the *AEO95* (excluding the *AEO96*, which is an estimate of the historical year 1995 based on partial year data). Across forecast years, the further out the forecast, the higher the average error, with the lowest error shown for the year 1985 at 13.3 percent.

The early *AEO*s—*AEO82* through *AEO86*—tended to have the highest average error, exacerbated especially by their forecasts for 1995. There was steady improvement in the *AEO*s through the *AEO90*, which averaged a 16.8-percent error. After the *AEO90*, the overpredictions for 1995 and 1996 adversely affected the overall average for subsequent *AEO*s.

The major factors in the overpredictions of coal prices were the assumptions concerning depletion effects, productivity improvements, capacity utilization, transportation, and the impacts of CAAA90. Depletion was assumed to overcome productivity improvements in the long run; in fact, the onset of such new technology as longwall mines, together with the growth of surface mining in the West, has made depletion a much less important factor. 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 high prices would follow the enactment of CAAA90 as the demand for low-sulfur coal increased. These price increases did not materialize, as productivity increases and transportation cost reductions made increased production from western mines possible at lower-than-anticipated prices.

Average Electricity Prices

Average electricity prices showed the best forecasting record among the prices examined here, with an average error of 11.0 percent (Table 16). As with all the price forecasts, because of the projections made 12 years earlier, the year with the highest average forecast errors was 1995, which had an average error of 15.5 percent. Except for two near-term forecasts of 1985 and 1989, price forecasts have been higher than actual. By publication, the *AEO83* had the highest average error of 18.2 percent, with the *AEO95* showing the lowest at 2.8 percent (with the exception of the *AEO97* estimate of the most recent historical year of 1996 based on partial year data). Recent *AEO*s, from the *Annual Energy Outlook 1992*[31] (*AEO92*) on, have had average errors of about 8.5 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, natural gas, and coal, and this had a strong effect on overestimating electricity prices, especially for the *AEO82* through the *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[32] 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, while the remaining

[31]Energy Information Administration, *Annual Energy Outlook 1992*, DOE/EIA-0383(92) (Washington, DC, January 1992).

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

Table 15. Coal Prices to Electric Utilities: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1996

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	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					3.14		0.82
AEO84	1.89	1.96	2.04	2.13	2.25	2.37					2.91		0.73
AEO85	1.68	1.75	1.82	1.89	1.98	2.09	2.18	2.27	2.36	2.42	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	0.62
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	0.40
AEO90					1.46	1.53					1.91		0.22
AEO91						1.51	1.59	1.67	1.76	1.85	1.91	1.97	0.37
AEO92							1.55	1.62	1.67	1.75	1.83	1.91	0.35
AEO93								1.49	1.53	1.58	1.67	1.71	0.24
AEO94									1.51	1.55	1.65	1.72	0.27
AEO95										1.42	1.46	1.48	0.13
AEO96											1.35	1.35	0.05
AEO97												1.36	0.07
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**	
Average Absolute Error	**0.22**	**0.29**	**0.37**	**0.42**	**0.47**	**0.52**	**0.38**	**0.44**	**0.48**	**0.53**	**0.76**	**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					137.9		57.0
AEO84	14.7	24.4	35.2	45.5	54.9	62.2					120.5		51.0
AEO85	1.9	10.7	21.1	28.8	36.5	43.1	51.0	60.8	69.5	78.7	90.6		44.8
AEO86		2.0	11.6	19.5	26.6	32.8	41.0	51.1	60.3	71.9	84.3	94.1	45.0
AEO87			0.9	6.7	14.6	20.4	27.8	37.2	46.6	56.5	68.0		31.0
AEO89				2.3	4.9	14.7	21.1	28.3	35.5	43.9	52.7	60.0	29.2
AEO90					0.7	5.1					44.7		16.8
AEO91						3.4	9.9	18.0	27.0	36.5	44.8	52.6	27.5
AEO92							7.0	15.0	19.9	29.0	38.7	48.1	26.3
AEO93								5.5	10.0	17.0	26.7	32.8	18.4
AEO94									8.5	14.6	24.9	33.5	20.4
AEO95										4.9	10.6	14.4	10.0
AEO96											2.7	4.6	3.7
AEO97												5.1	5.1
Average Absolute Percent Error	**13.3**	**18.6**	**24.6**	**28.9**	**32.1**	**35.4**	**26.3**	**30.9**	**34.6**	**39.2**	**57.5**	**38.4**	**34.8**

AEO = Annual Energy Outlook.

Btu = British thermal unit.

Sources: **Actual Values:** Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(97/05) (Washington, DC, May 1997). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-97) (Washington, DC, April 1983 - December 1996).

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 forecasts for gross domestic product show an average error of 5.0 percent (Table 17). Most of the projections have been 10 percent or less from actual, with the exception of some of the forecasts in the *AEO83*, *AEO84*, *AEO85*, *AEO86*, and *AEO89* for the mid-1990s, which ranged up to 29.1 percent above the actual GDP. In general, from the *AEO82* through the *AEO90*, the GDP forecasts tended to be underestimated for the earlier years and overestimated for the later years. In subsequent reports, the GDP has been consistently underestimated.

Table 16. Average Electricity Prices: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1996

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	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					9.60		1.20
AEO84	6.63	6.88	7.14	7.38	7.59	7.84					8.85		0.96
AEO85	6.62	6.89	7.18	7.40	7.60	7.79	7.95	8.07	8.14	8.22	8.33		1.03
AEO86		6.67	6.89	7.05	7.20	7.38	7.50	7.46	7.47	7.63	7.86	8.07	0.71
AEO87			6.63	6.69	6.96	7.17	7.40	7.54	7.67	7.82	8.03		0.64
AEO89				6.50	6.78	7.13	7.39	7.54	7.62	7.77	7.93	8.09	0.68
AEO90					6.49	6.73					7.74		0.33
AEO91						6.94	7.36	7.61	7.78	8.05	8.15	8.16	0.91
AEO92							7.01	7.20	7.34	7.53	7.69	7.81	0.58
AEO93								7.19	7.30	7.43	7.62	7.72	0.58
AEO94									6.98	7.13	7.42	7.57	0.38
AEO95										6.95	7.13	7.16	0.19
AEO96											7.28	7.32	0.42
AEO97												7.03	0.16
Actual Value	**6.40**	**6.40**	**6.40**	**6.40**	**6.50**	**6.60**	**6.70**	**6.80**	**6.90**	**6.90**	**6.90**	**6.87**	
Average Absolute Error	**0.26**	**0.38**	**0.60**	**0.70**	**0.74**	**0.84**	**0.73**	**0.72**	**0.64**	**0.71**	**1.07**	**0.79**	**0.74**
					(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					39.1		18.2
AEO84	3.6	7.5	11.6	15.3	16.8	18.7					28.3		14.6
AEO85	3.4	7.7	12.2	15.6	16.9	18.0	18.7	18.7	18.0	19.1	20.7		15.4
AEO86		4.2	7.6	10.1	10.7	11.9	11.9	9.7	8.3	10.6	13.9	17.5	10.6
AEO87			3.6	4.6	7.0	8.6	10.5	10.8	11.1	13.3	16.3		9.6
AEO89				1.5	4.3	8.0	10.2	11.0	10.4	12.5	15.0	17.7	10.1
AEO90					-0.2	2.0					12.1		4.8
AEO91						5.2	9.8	11.9	12.8	16.6	18.1	18.7	13.3
AEO92							4.6	5.9	6.4	9.1	11.5	13.6	8.5
AEO93								5.8	5.8	7.7	10.4	12.4	8.4
AEO94									1.1	3.4	7.6	10.2	5.6
AEO95										0.8	3.4	4.3	2.8
AEO96											5.5	6.6	6.1
AEO97												2.4	2.4
Average Absolute Percent Error	**4.1**	**6.0**	**9.3**	**11.0**	**11.4**	**12.7**	**11.0**	**10.5**	**9.2**	**10.3**	**15.5**	**11.5**	**11.0**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** 1985-1995—Energy Information Administration (EIA), *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). 1996—EIA, *Monthly Energy Review*, DOE/EIA-0035(97/05) (Washington, DC, May 1997). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-97) (Washington, DC, April 1983 - December 1996).

The major reason for the pattern of overprediction 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, overpredicted long-term growth beyond 1991. Conversely, the underestimates of the later *AEO*s are due in part to overprediction of world oil prices, which tend to dampen economic growth, plus several other factors such as actual utility bond rates being lower than predicted.

Table 17. Gross Domestic Product: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1996

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	Average Absolute Error
(Nominal Billion Dollars)													
AEO82	3939	4306	4733	5201	5712	6288							228
AEO83	3919	4264	4650	5086	5549	6053					9362		432
AEO84	3910	4191	4589	5031	5490	5979					9098		393
AEO85	3882	4103	4436	4793	5207	5658	6158	6702	7252	7836	8486		453
AEO86		4203	4434	4741	5015	5371	5795	6244	6726	7270	7875	8524	343
AEO87			4483	4701	5035	5389	5773	6190	6666	7175	7716		259
AEO89				4857	5182	5575	6013	6483	6987	7525	8106	8756	445
AEO90					5236	5550					7882		342
AEO91						5457	5695	6078	6399	6738	7145	7607	166
AEO92							5648	5992	6346	6710	7115	7530	190
AEO93								5941	6339	6714	7117	7542	183
AEO94									6264	6622	6944	7298	299
AEO95										6761	7090	7418	166
AEO96											7057	7356	211
AEO97												7585	5
Actual Value	**4181**	**4422**	**4692**	**5050**	**5439**	**5744**	**5917**	**6244**	**6553**	**6936**	**7254**	**7580**	
Average Absolute Error	**268**	**209**	**152**	**187**	**244**	**284**	**182**	**210**	**285**	**355**	**677**	**323**	**314**
(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					29.1		6.8
AEO84	-6.5	-5.2	-2.2	-0.4	0.9	4.1					25.4		6.4
AEO85	-7.1	-7.2	-5.5	-5.1	-4.3	-1.5	4.1	7.3	10.7	13.0	17.0		7.5
AEO86		-5.0	-5.5	-6.1	-7.8	-6.5	-2.1	0.0	2.6	4.8	8.6	12.4	5.6
AEO87			-4.5	-6.9	-7.4	-6.2	-2.4	-0.9	1.7	3.5	6.4		4.4
AEO89				-3.8	-4.7	-2.9	1.6	3.8	6.6	8.5	11.7	15.5	6.6
AEO90					-3.7	-3.4					8.7		5.3
AEO91						-5.0	-3.7	-2.7	-2.4	-2.9	-1.5	0.4	2.6
AEO92							-4.5	-4.0	-3.2	-3.3	-1.9	-0.7	2.9
AEO93								-4.9	-3.3	-3.2	-1.9	-0.5	2.7
AEO94									-4.4	-4.5	-4.3	-3.7	4.2
AEO95										-2.5	-2.3	-2.1	2.3
AEO96											-2.7	-3.0	2.8
AEO97												0.1	0.1
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**	**4.3**	**5.0**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** 1985-1995—Council of Economic Advisors, *Economic Report of the President* (Washington, DC, February 1996). 1996—U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, February 1997). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-97) (Washington, DC, April 1983 - December 1996).

Low World Oil Price Case

All the proceeding analysis has focused on the reference case projections from the *AEO*s. In fact, all the *AEO*s have presented projections for more than one case. During the period covered in this paper, the reports have included two to seven cases, which have varied key reference case assumptions and examined the impacts of those assumptions across all energy markets. Most frequently, the alternative cases have varied the macroeconomic growth or world oil market assumptions, although other cases have been examined, such as different oil and gas resource base assumptions. Also, many *AEO*s have included a variety of additional cases that have analyzed the impacts of different assumptions on a portion of the energy market. *AEO97*, for example, included 23 such cases in addition to the reference case, high and low macroeconomic growth cases, and high and low world oil price cases.

Because the world oil price projections have usually been too low with a relatively high error, the price projections for the low world oil price cases are also presented here, along with the accompanying petroleum consumption, crude oil production, and net petroleum imports projections. Some caution must be used in interpreting the results from these cases. First, during the mid-1980s, attention in the *AEO*s was focussed on international and domestic oil markets. In the *AEO85*, *AEO86*, and *AEO87*, the low world oil price case included high economic growth assumptions that would tend to increase projected energy consumption beyond the level caused by the lower prices alone.

Conversely, the high world oil price cases in those three reports included low economic growth assumptions. The cases were designed in this way to examine the uncertainty in petroleum imports that results from changes in both prices and economic growth. In fact, in *AEO85*, the alternative cases were called low and high oil imports cases to highlight the purpose of the cases. For all the other *AEO*s examined in this paper, the low world oil price cases varied only world oil market assumptions, although some feedback effect on economic growth from low prices was captured in the modeling systems.

The second cautionary note concerns the definition of low world oil prices. Through the years, the low and high oil price cases have sometimes been defined by varying only the OPEC productive capacity assumptions. At other times, other world oil market assumptions have varied, such as production from non-OPEC countries, world economic growth, and world demand for oil. In addition, some of the *AEO*s attempted to define a broad band of uncertainty around the reference case oil price projection, while others defined a more narrow range. In short, the definition of the low world oil price case has not been consistent. Nevertheless, the presentation of these results should highlight some of the ranges of the forecasts presented over the years.

World oil prices under low oil price assumptions have a considerably improved error rate (Table 18)—an average absolute percent error of 30.8, compared to 53.1 for the reference case projections. The lower error rate occurs, in part, because of the lower prices but also because there are fewer of the older projections available for comparison. Similarly to the reference case projections, the largest errors are for the year 1995 in the earlier *AEO*s. Very high estimates of the world oil price in 1995 also cause the *AEO83* and *AEO84* to have the highest error rates by publication.

Compared to the reference case projections, oil prices in the low oil price cases display considerably more cases of underestimations. The projections made around the time of the oil price collapse of 1986 and for several years thereafter defined low oil price cases with very modest price increases that underestimated the rebound that occurred in world oil prices. Also, the oil prices in the low price cases in the most recent *AEO*s were relatively flat or even declining and, therefore, underestimated the price increases that occurred in 1995 and again in 1996.

Total petroleum consumption in the low world oil price cases (Table 19) had a slightly greater average percent error than in the reference cases—3.6 percent compared to 2.8 percent. The majority of the errors in the reference case were underpredictions, many of which became overpredictions with the lower prices, even when the lower prices were still too high relative to the actual prices, perhaps indicating embedded price elasticities that were too high.

The average percent error for crude oil production was also slightly higher at 4.9 percent (Table 20) than in the reference case, which had an average error of 4.2 percent for oil production. Earlier *AEO*s tended to overpredict oil production, particularly for the 1980s, and these projections improved with lower oil prices; however, the underpredictions for the later years were exacerbated by the lower price assumptions. Most striking are the large underpredictions for production in the low price cases in the earlier *AEO*s, even though the prices were still considerably higher than actual, indicating a very robust price response relative to the reference case projections. With generally lower production and higher consumption, the projections for net petroleum imports in the low price cases mostly tended to overpredict imports (Table 21). In the reference cases, the average percent error for net imports was 10.1, and the error increased to 17.5 percent in the low price cases.

Conclusion

Although a primary function of the models used by EIA to produce the forecasts in the *AEO* has been and remains the analysis of alternatives policies, many readers of the *AEO* use the projected numbers as forecasts for their own purposes. Thus, it is useful for EIA

Table 18. World Oil Prices, Low Price Case: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1996

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	Average Absolute Error
						(Dollars per Barrel)							
AEO82	23.58	24.14	26.44	20.88	33.53	36.85							9.79
AEO83	24.07	24.57	25.37	28.23	32.75	37.34					53.79		14.47
AEO84	24.79	25.49	26.28	28.36	29.55	30.83					42.53		11.65
AEO85	26.00	21.59	21.20	21.96	24.03	26.27					34.31		6.67
AEO86		14.57	11.46	12.55	13.82	15.25					28.30		5.20
AEO87			18.11	14.10	14.94	15.85	16.72	17.46	18.54	20.70	23.63		2.93
AEO89				14.70	12.92	14.01	15.14	16.03	17.64	19.25	20.87	22.55	3.30
AEO90					17.10	15.03					17.15		2.58
AEO91						22.00	19.75	20.30	20.83	21.29	21.84	22.27	2.89
AEO92							17.36	15.92	16.66	17.48	18.39	19.10	1.47
AEO93								17.29	17.07	16.28	16.59	16.46	1.46
AEO94									16.81	16.19	16.24	16.33	1.62
AEO95										15.23	14.88	14.38	2.91
AEO96											16.29	14.42	3.50
AEO97												19.90	0.67
Actual Value	**26.99**	**14.00**	**18.13**	**14.56**	**18.08**	**21.76**	**18.70**	**18.20**	**16.14**	**15.51**	**17.14**	**20.57**	
Average Absolute Error	**2.38**	**8.07**	**5.57**	**6.26**	**7.63**	**7.93**	**1.98**	**1.64**	**1.78**	**2.63**	**8.55**	**3.31**	**5.40**
						(Percent Error)							
AEO82	-12.6	72.4	45.8	43.4	85.4	69.4							54.8
AEO83	-10.8	75.5	40.0	93.9	81.1	71.6					213.8		83.8
AEO84	-8.1	82.0	44.9	94.8	63.4	41.7					148.1		69.0
AEO85	-3.7	54.2	16.9	50.9	32.9	20.7					100.2		39.9
AEO86		4.1	-36.8	-13.8	-23.5	-29.9					65.1		28.9
AEO87			-0.1	-3.2	-17.4	-27.2	-10.6	-4.1	14.9	33.5	37.9		16.5
AEO89				1.0	-28.5	-35.6	-19.0	-11.9	9.3	24.1	21.8	9.6	17.9
AEO90					-5.4	-30.9					0.1		12.1
AEO91						1.1	5.6	11.5	29.0	37.3	27.4	8.3	17.2
AEO92							-7.2	-12.5	3.2	12.7	7.3	-7.1	8.3
AEO93								-5.0	5.8	5.0	-3.2	-20.0	7.8
AEO94									4.1	4.4	-5.3	-20.6	8.6
AEO95										-1.8	-13.2	-30.1	15.0
AEO96											-5.0	-29.9	17.4
AEO97												-3.3	3.3
Average Absolute Percent Error	**8.8**	**57.6**	**30.7**	**43.0**	**42.2**	**36.5**	**10.6**	**9.0**	**11.1**	**17.0**	**49.9**	**16.1**	**30.8**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** 1985-1995—Energy Information Administration (EIA), *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). 1996—EIA, *Monthly Energy Review*, DOE/EIA-0035(97/05) (Washington, DC, May 1997). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-97) (Washington, DC, April 1983 - December 1996).

analysts and the users of the *AEO* to understand the differences between the earlier projections and actual values.

Throughout the *AEO*s, the variables with the highest average forecast 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 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 overprediction of prices is the most striking feature of this evaluation. In general, more rapid technological improvements, the erosion of OPEC's market power,

Table 19. Total Petroleum Consumption, Low Price Case: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1996

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	Average Absolute Error
						(Million Barrels per Day)							
AEO82	18.94	19.35	19.29	19.11	18.83	18.86							2.35
AEO83	16.12	16.55	16.92	17.15	17.27	17.41					19.14		0.42
AEO84	15.97	16.01	16.30	16.59	16.84	17.24					19.25		0.55
AEO85	15.79	16.10	16.35	16.37	16.48	16.61					17.76		0.39
AEO86		16.10	16.87	16.96	16.94	17.11					17.52		0.24
AEO87			16.52	16.90	17.62	17.91	18.26	18.52	18.71	18.70	18.74		0.92
AEO89				17.01	17.39	17.76	17.98	18.17	18.23	18.35	18.47	18.78	0.71
AEO90					17.28	17.70					19.40		0.81
AEO91						16.95	16.79	17.31	17.56	17.75	17.94	18.10	0.16
AEO92							16.78	17.27	17.65	17.96	18.30	18.46	0.29
AEO93								17.10	17.63	18.14	18.67	18.95	0.51
AEO94									17.68	18.11	18.44	18.77	0.52
AEO95										17.50	18.13	18.31	0.24
AEO96											17.87	18.28	0.10
AEO97												18.19	0.04
Actual Value	**15.73**	**16.28**	**16.67**	**17.28**	**17.33**	**16.99**	**16.71**	**17.03**	**17.24**	**17.72**	**17.72**	**18.23**	
Average Absolute Error	**0.98**	**0.79**	**0.65**	**0.65**	**0.46**	**0.61**	**0.74**	**0.64**	**0.67**	**0.42**	**0.74**	**0.29**	**0.62**
						(Percent Error)							
AEO82	20.4	18.9	15.7	10.6	8.7	11.0							14.2
AEO83	2.5	1.7	1.5	-0.8	-0.3	2.5					8.0		2.5
AEO84	1.5	-1.7	-2.2	-4.0	-2.8	1.5					8.6		3.2
AEO85	0.4	-1.1	-1.9	-5.3	-4.9	-2.2					0.2		2.3
AEO86		-1.1	1.2	-1.9	-2.3	0.7					-1.1		1.4
AEO87			-0.9	-2.2	1.7	5.4	9.3	8.7	8.5	5.5	5.8		5.3
AEO89				-1.6	0.3	4.5	7.6	6.7	5.7	3.6	4.2	3.0	4.1
AEO90					-0.3	4.2					9.5		4.6
AEO91						-0.2	0.5	1.6	1.9	0.2	1.2	-0.7	0.9
AEO92							0.4	1.4	2.4	1.4	3.3	1.2	1.7
AEO93								0.4	2.3	2.4	5.4	3.9	2.9
AEO94									2.6	2.2	4.1	2.9	2.9
AEO95										-1.2	2.3	0.4	1.3
AEO96											0.8	0.3	0.5
AEO97												-0.2	0.2
Average Absolute Percent Error	**6.2**	**4.9**	**3.9**	**3.7**	**2.7**	**3.6**	**4.4**	**3.8**	**3.9**	**2.3**	**4.2**	**1.6**	**3.6**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** 1985-1995—Energy Information Administration (EIA), *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). 1996—EIA, *Monthly Energy Review*, DOE/EIA-0035(97/05) (Washington, DC, May 1997). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-97) (Washington, DC, April 1983 - December 1996).

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 overall predictions for 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, regulation, and standards.

Table 20. Crude Oil Production, Low Price Case: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1996

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	Average Absolute Error
						(Million Barrels per Day)							
AEO82	8.63	8.58	8.47	8.34	8.17	7.71							0.28
AEO83	8.57	8.46	8.33	8.21	8.24	8.04					6.97		0.35
AEO84	8.86	8.65	8.49	8.26	7.99	7.80					5.37		0.34
AEO85	8.92	8.84	8.81	8.56	8.07	7.58					5.46		0.41
AEO86		8.75	8.44	8.01	7.49	7.10					5.61		0.27
AEO87			8.31	7.99	7.87	7.41	7.06	6.76	6.49	6.23	6.03		0.29
AEO89				8.18	7.80	7.54	7.08	6.64	6.32	6.05	5.79	5.60	0.45
AEO90					7.65	7.23					5.71		0.34
AEO91						7.23	6.98	6.87	6.67	6.44	6.11	5.77	0.34
AEO92							7.29	6.95	6.55	6.29	5.93	5.59	0.42
AEO93								7.20	6.80	6.51	6.08	5.62	0.31
AEO94									6.86	6.48	6.12	5.82	0.32
AEO95										6.54	6.14	5.78	0.41
AEO96											6.48	6.17	0.19
AEO97												6.47	0.00
Actual Value	**8.97**	**8.68**	**8.35**	**8.14**	**7.61**	**7.36**	**7.42**	**7.17**	**6.85**	**6.66**	**6.56**	**6.47**	
Average Absolute Error	**0.23**	**0.12**	**0.15**	**0.16**	**0.33**	**0.27**	**0.31**	**0.30**	**0.24**	**0.30**	**0.64**	**0.62**	**0.34**
						(Percent Error)							
AEO82	-3.8	-1.2	1.4	2.5	7.3	4.8							3.5
AEO83	-4.5	-2.5	-0.2	0.9	8.2	9.3					6.3		4.6
AEO84	-1.2	-0.3	1.7	1.5	5.0	6.1					-18.1		4.8
AEO85	-0.6	1.8	5.5	5.2	6.0	3.1					-16.8		5.6
AEO86		0.8	1.1	-1.6	-1.6	-3.5					-14.5		3.8
AEO87			-0.5	-1.8	3.4	0.7	-4.8	-5.7	-5.2	-6.5	-8.1		4.1
AEO89				0.5	2.5	2.5	-4.5	-7.4	-7.7	-9.2	-11.7	-13.5	6.6
AEO90					0.5	-1.7					-13.0		5.0
AEO91						-1.7	-5.9	-4.2	-2.6	-3.3	-6.9	-10.8	5.1
AEO92							-1.7	-3.1	-4.3	-5.6	-9.6	-13.6	6.3
AEO93								0.4	-0.7	-2.3	-7.3	-13.2	4.8
AEO94									0.2	-2.7	-6.7	-10.1	4.9
AEO95										-1.8	-6.4	-10.7	6.3
AEO96											-1.2	-4.7	2.9
AEO97												0.0	0.0
Average Absolute Percent Error	**2.5**	**1.3**	**1.7**	**2.0**	**4.3**	**3.7**	**4.2**	**4.2**	**3.5**	**4.5**	**9.7**	**9.6**	**4.9**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** 1985-1995—Energy Information Administration (EIA), *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). 1996—EIA, *Monthly Energy Review*, DOE/EIA-0035(97/05) (Washington, DC, May 1997). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-97) (Washington, DC, April 1983 - December 1996).

Table 21. Net Petroleum Imports, Low Price Case: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1996

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	Average Absolute Error
						(Million Barrels per Day)							
AEO82	8.67	9.17	9.25	9.17	9.04	9.47							3.03
AEO83	5.56	6.15	6.70	6.98	7.00	7.36					9.87		0.79
AEO84	5.06	5.46	6.00	6.45	6.94	7.56					11.74		0.79
AEO85	4.17	4.38	5.27	5.47	6.08	6.70					10.04		0.95
AEO86		5.15	5.38	6.75	7.20	7.77					9.60		0.55
AEO87			5.81	6.46	7.69	8.36	9.06	9.61	10.04	10.24	10.49		1.58
AEO89				6.28	7.17	7.90	8.51	9.17	9.52	9.92	10.28	10.75	1.52
AEO90					7.33	8.04					10.96		1.36
AEO91						7.28	7.40	8.07	8.50	8.89	9.38	9.85	0.95
AEO92							6.86	7.86	8.60	9.13	9.80	10.25	1.16
AEO93								7.25	8.36	9.14	10.04	10.69	1.31
AEO94									8.05	8.90	9.42	10.03	1.11
AEO95										8.09	9.11	9.71	0.85
AEO96											8.43	9.16	0.64
AEO97												8.49	0.07
Actual Value	**4.29**	**5.44**	**5.91**	**6.59**	**7.20**	**7.16**	**6.63**	**6.94**	**7.62**	**8.05**	**7.89**	**8.42**	
Average Absolute Error	**1.64**	**1.16**	**0.92**	**0.69**	**0.51**	**0.77**	**1.33**	**1.45**	**1.23**	**1.14**	**2.05**	**1.45**	**1.22**
						(Percent Error)							
AEO82	102.1	68.6	56.5	39.2	25.6	32.3							54.0
AEO83	29.6	13.1	13.4	5.9	-2.8	2.8					25.1		13.2
AEO84	17.9	0.4	1.5	-2.1	-3.6	5.6					48.8		11.4
AEO85	-2.8	-19.5	-10.8	-17.0	-15.6	-6.4					27.2		14.2
AEO86		-5.3	-9.0	2.4	0.0	8.5					21.7		7.8
AEO87			-1.7	-2.0	6.8	16.8	36.7	38.5	31.8	27.2	33.0		21.6
AEO89				-4.7	-0.4	10.3	28.4	32.1	24.9	23.2	30.3	27.7	20.2
AEO90					1.8	12.3					38.9		17.7
AEO91						1.7	11.6	16.3	11.5	10.4	18.9	17.0	12.5
AEO92							3.5	13.3	12.9	13.4	24.2	21.7	14.8
AEO93								4.5	9.7	13.5	27.2	27.0	16.4
AEO94									5.6	10.6	19.4	19.1	13.7
AEO95										0.5	15.5	15.3	10.4
AEO96											6.8	8.8	7.8
AEO97												0.8	0.8
Average Absolute Percent Error	**38.1**	**21.4**	**15.5**	**10.5**	**7.1**	**10.7**	**20.0**	**20.9**	**16.1**	**14.1**	**25.9**	**17.2**	**17.5**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** 1985-1995—Energy Information Administration (EIA), *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). 1996—EIA, *Monthly Energy Review*, DOE/EIA-0035(97/05) (Washington, DC, May 1997). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-97) (Washington, DC, April 1983 - December 1996).

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

This paper presents a summary of the National Energy Modeling System/Annual Energy Outlook conference held on March 17, 1997. The remarks for each speaker were summarized by the session moderators but 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 many cases, in order to have a wider range of opinions at each session, the speakers chosen have different views from those of EIA.

Introduction

On March 17, 1997, the Office of Integrated Analysis and Forecasting (OIAF), Energy Information Administration (EIA), hosted the fifth 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.

At the first of these conferences, analysts from OIAF presented plans for the National Energy Modeling System (NEMS), which was under development at that time. Speakers knowledgeable in each topic area were invited to comment on the proposed modeling methodologies. The following year, analysts presented the results from the *Annual Energy Outlook 1994*,[1] the first *Annual Energy Outlook* that contained results from NEMS, and plans for future development, followed by commentary from invited speakers. Since then, the conferences have focussed less on specific projections and model developments and more on energy issues and their potential impacts on energy markets.

New Generating Technologies: Trends and Possible Breakthroughs

Moderator: David J. Schoeberlein, Energy Information Administration

The objective of this session was to examine the current condition of and possible improvements to electricity generating technologies from the perspective of competitive electricity markets.

Technology Breakthroughs for a Sustainable Electric Future

Charles D. Siebenthal, Electric Power Research Institute

Competition is coming to electricity markets worldwide. Because the new model for electricity markets is tending toward competition and away from regulation, suppliers and consumers will need to seek out new processes that optimize the supply, delivery, and usage chain while achieving environmental goals. In some cases, technological breakthroughs will be needed if electricity is to achieve the commodity price structure of true competitive markets. Obstacles to competition that must be overcome include the current inability to store electricity, a transmission system that was primarily designed for reliability rather than the needs of a competitive market, and uncertainty regarding the depth and scope of future emission mandates for pollutants.

Competitive markets will dictate that the current transmission and distribution system be brought into the 21st century. Urban distribution systems have become technologically obsolete and environmentally obtrusive. Because the cost of updating and maintaining the system may be higher than generated revenues, rural systems may become a liability. Selection of new generating technologies will require deeper consideration of the economic and environmental factors governing capacity expansion than it has in the past. A stringent carbon dioxide (CO_2) policy could force a deemphasis of fossil fuels. Although nuclear and renewable technologies are obvious alternatives, concerns about safety and waste disposal for nuclear plants and the intermittent nature of most renewable technologies constrain

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

their value as substitutes. From an economic standpoint, old incentives for long-range planning are rapidly disappearing. Old rewards are being replaced by new risks. Consequently, technologies that have low costs and rapid payback with relatively low perceived risks will be the technologies of choice in the future.

The Evaluation of Generating Technology Options 1995 to 2015

John Molburg, Argonne National Laboratory

In addition to the high cost of electricity relative to existing technologies, advanced technologies will need to cross other boundaries to penetrate competitive electricity markets. This boundary is also defined by issues surrounding the methods used to replace the aging technology base and address future environmental policy.

By 1998, more than 3,500 fossil-fired generating units will be more than 30 years old. Because siting and permitting are greatly simplified, capital cost savings of up to 50 percent can be achieved by using existing generating stations. To date, more than 3 gigawatts of existing capacity have been repowered by replacing existing fossil-fired power plants with new generating equipment and technologies. Repowering usually results in a substantial improvement in efficiency, with improvements up to 25 percent possible. As a result, repowering leads to reductions in pollution emissions and may also play a significant role in reducing greenhouse gas emissions. Replacing an existing fossil-steam plant with natural gas combined-cycle or integrated coal gasification combined-cycle (IGCC) technologies can greatly reduce carbon dioxide emissions. Of the two, the high cost of treating large gas volumes favors IGCC. Using IGCC, minimal costs for CO_2 recovery of around 1.5 cents per kilowatthour could be achieved. Sequestration of CO_2 in depleted oil and gas fields could be accomplished at costs as low as 2.3 cents per kilowatthour. Consequently, total CO_2 removal costs could be as low as $70 per ton.

Deregulation may adversely affect the availability of capital for the infrastructure needed to remove and sequester CO_2. In this case, it would be more cost-effective to seek out processes that promise higher efficiencies, such as the Kalina cycle, for existing steam-driven systems and consequently reduce the amount of CO_2 produced. Existing steam boilers use a heat source such as coal, oil, or natural gas to produce high-pressure steam that drives a turbine. The excess steam is condensed into water, which is then pumped back to the boiler in a loop called the Rankine cycle. The Kalina cycle mixes the water with ammonia, which raises efficiency at the heat stage of the cycle. Because ammonia condenses less readily than water, this can lead to smaller steam turbines that tend to negate the gains produced in the heat stage. In the Kalina cycle, most of the ammonia is drawn off before the condensation stage. Implementation of the Kalina cycle can boost thermal efficiency by as much as 40 percent.

Projected Performance and Costs of Emerging Power Systems in the 2010 and Beyond Time Period

Dwain F. Spencer, SIMTECHE

Currently, the technologies of choice for new capacity by electricity suppliers are natural gas combustion turbines and combined-cycles for peaking / intermediate and baseload capacity, respectively. Estimates of achievable market penetration for new generating technologies must be contrasted with the known and projected cost and performance characteristics of current turbine-based designs.

Table 1 compares the projected levelized costs of electricity from advanced gas turbine designs with those from other advanced technologies under varying capital cost, capacity factor, and heat rate assumptions. The analysis is based on current dollars and assumes a 2.5-percent annual escalation rate over a 30-year levelization period for plants built in 2010. Because general comparisons of this type do not take into account all the strengths and weaknesses that a particular generating technology might have for specific local applications, discretion should be exercised when comparing the cost of one technology to another—especially when costs are relatively close. However, several strong implications can be deduced from the numbers.

First, only advanced coal, binary-cycle geothermal, and perhaps solar thermal power systems will be able to compete with natural-gas-fired combined-cycle plants for baseload power, assuming that the projected mature-plant capital costs are achieved and there are no major escalations of capital costs over the next 15 years. Second, in the absence of carbon control requirements, advanced light-water reactors may have electricity costs 30 to 40 percent greater than advanced turbine-based systems, while biomass gasification technologies could have costs 60 to 100 percent greater than advanced coal. Third, in areas of good wind availability, wind turbines

Table 1. Comparison of Levelized Electricity Costs for Advanced Generating Technologies Built in 2010

Technology	Capacity (Megawatts)	Capital Cost (Dollars per Kilowatthour)	Capacity Factor (Percent)	Heat Rate (Btu per Kilowatthour)	Levelized Cost of Electricity[a] (Cents per Kilowatthour)
Advanced combustion turbine	230	250-400	20 25	8,900	6.7-7.9; 7.8-9.0 5.9-6.9; 7.0-8.0
Advanced combined-cycle	350	400-600	65	6,000	4.6-5.2; 5.3-5.9
Coal gasification combined-cycle	400-500	1,300-2,500	65	8,000 7,000	5.7-8.8 5.5-8.6
Advanced light-water reactor	1,300	2,000-2,900	65	10,300	7.0-9.7
Geothermal binary cycle	50	1,800-3,400	65	NA	5.7-10.6
Biomass	100	1,600-3,600	65	9,000	8.7-14.6
Solar thermal	200 0.025	1,900-7,200 800-8,300	65 25	NA NA	5.8-22.0 6.4-55.0
Wind	50	600-1,100	30	NA	4.8-7.5
Photovoltaic	50	1,500-5,000	20 25	NA NA	13.0-41.0 10.5-33.5

[a]Ranges in the levelized cost of electricity reflect the range of capital costs within the technology. Where there are two sets of ranges—for advanced combustion turbine and advanced combined-cycle technologies—the lower range uses natural gas prices from the *Annual Energy Outlook 1997* (*AEO97*) and the higher range uses a higher escalation rate in gas prices chosen by SIMTECHE.

Note: Btu = British thermal unit. NA = not applicable.

Sources: Advanced natural gas turbines and combined-cycle: General Electric and Westinghouse. Coal gasification combined-cycle: Electric Power Research Institute (EPRI), SIMTECHE, and U.S. Department of Energy, Office of Fossil Energy. Advanced light-water reactor: EPRI and Oak Ridge National Laboratory. Geothermal, biomass, solar thermal, and photovoltaic: EPRI and National Renewable Energy Laboratory. Wind: EPRI. *AEO97*: Energy Information Administration, *Annual Energy Outlook 1997*, DOE/EIA-0383(97) (Washington, DC, December 1996).

may produce electricity for peaking power at lower cost than advanced simple-cycle turbines. Electricity produced from solar photovoltaic systems is projected to cost 30 to 50 percent more than electricity from advanced turbines used for peaking power. Finally, in areas with high solar insolation (greater than 1,800 kilowatthours per square meter per year) and sufficient peaking power growth rates (2.5 percent annually or greater), electricity costs from solar thermal technologies could be comparable to gas turbine power costs. However, increasing the assumed annualized capacity factor from 65 percent to a range of 75 to 85 percent would make all baseload power plants more competitive with advanced gas turbine combined-cycles. At a capacity factor of 85 percent, the cost of electricity for nuclear, biomass, and geothermal technologies would be 1.5 to 2 cents lower than for advanced gas systems.

Oil Import Dependence: U.S. Supply and Refining Capacity

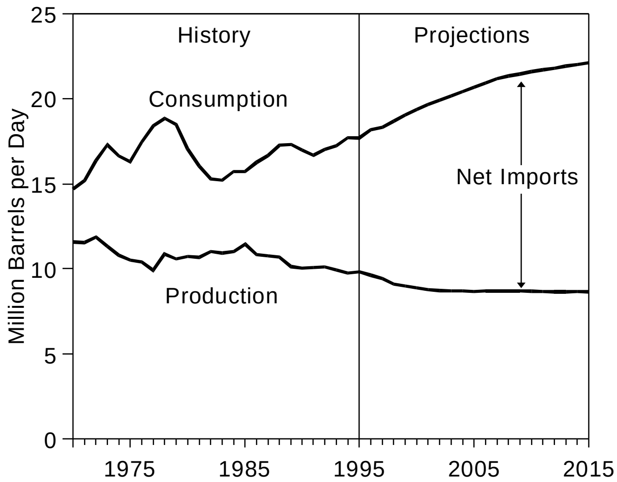
Moderator: James M. Kendell, Energy Information Administration

The objectives of this session were to recognize the increasing U.S. dependence on foreign oil and to discuss the resulting economic and national security vulnerability.

Background

Net imports of crude oil and petroleum products are projected to increase from 44 percent of total consumption in 1995 to 61 percent by 2015, according to the *AEO97* reference case (Figure 1). The value of imported oil is projected to increase from about $50 billion in 1995 to more than $100 billion in 2015 in constant 1995 dollars. However, if Canada and Mexico

Figure 1. Petroleum Production, Consumption, and Imports, 1970-2015



History: Energy Information Administration, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). **Projections:** *AEO97*, Table A11. **Note:** Production includes domestic crude oil and natural gas plant liquids, other crude supply, other inputs, and refinery processing gain.

are excluded from the calculation (because they are more secure sources of supply), import dependence rises to less than 50 percent over the forecast period.

Overview of Oil Imports, Sanctions and Energy Policies

Lawrence J. Goldstein, Petroleum Industry Research Foundation, Inc.

Growth in oil imports from Canada, Mexico, Venezuela, Colombia, and the U.S. deepwater Gulf of Mexico will limit growth in dependence on Persian Gulf oil over the next 5 to 10 years. Persian Gulf imports will not grow as a share and will shrink as an absolute volume, as nearby sources back out Persian Gulf barrels. Absent any shocks from political events, oil prices are expected to drop over the next 5 years, as technology reduces oil production costs. Embargoes and trade sanctions to force other governments to act on drugs or terrorism are costly, ineffective, outdated foreign policy tools, which threatened the diversity of U.S. oil supplies. Sanctions can be likened to “friendly fire” on the battlefield, given their damage to U.S. relationships with other democracies and their damage to U.S. businesses.

A review of the oil market in 1995 and 1996 shows that 1996 was the first year, excluding war years, in which net new supply failed to meet net new demand; however, supply is expected to exceed demand in 1997, and prices are expected to decline below $20 per barrel. U.S. oil production began to increase in the second half of 1996 after a long decline, and oil production in the U.S. deepwater Gulf of Mexico is expected to grow by more than 1 million barrels per day over the next 5 years. The focus of policymakers should be on oil import vulnerability, not on oil import dependence.

America’s Energy Dilemma: How to Maintain a Cheap Oil Policy and Viable Domestic Oil and Gas Industry

Roy W. Willis, Independent Petroleum Association of America

Technology has driven changes in U.S. oil production, particularly in the Gulf of Mexico, and has also prolonged the economic life of the 478,000 U.S. wells that produce less than 3 barrels per day. U.S. policies should encourage investment in oil and gas prospects in the United States, but they do not always do that. On one hand, America wants to keep crude oil and gasoline as cheap as it possibly can. On the other hand, it sometimes wants to encourage domestic production. In the future, much of the new domestic production will occur on public lands, although Government regulation is making that increasingly difficult.

The Independent Petroleum Association of America is currently preparing comments on more than 50 regulatory proposals affecting the oil and gas industry. The U.S. tax code makes the United States one of the most expensive places in the world to produce oil and gas, and pending changes in natural gas accounting, delayed rental payments, and enhanced oil recovery could make it even more expensive. There are also proposals to eliminate foreign tax credits. Depletion allowances and expensing of drilling costs should not be viewed as “corporate welfare,” but as ordinary and necessary business expenses. Finally, the environmental risks of offshore oil production are 200 to 300 times less than the risks of bringing in oil on aging, foreign ships.

Energy Security: Analysis of U.S. Vulnerability to Oil Shocks and Options for Mitigating their Effects

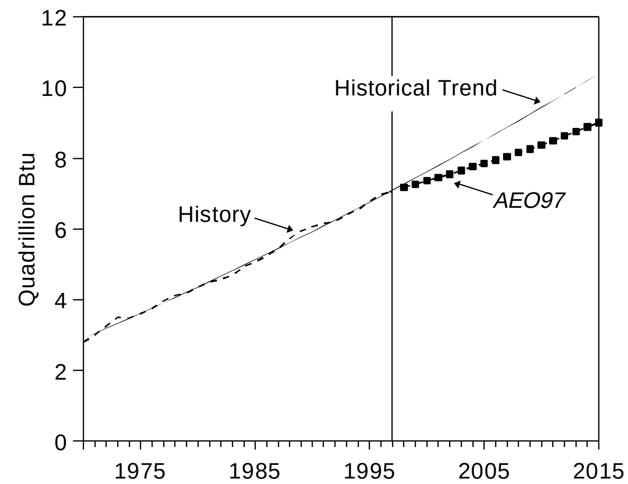
Godwin M. Agbara, U.S. General Accounting Office

The report *Evaluating U.S. Vulnerability to Oil Shocks and Options for Mitigating Their Effects*,[2] was designed primarily to quantify the economic benefits of importing

[2]U.S. General Accounting Office, *Energy Security: Evaluating U.S. Vulnerability to Oil Shocks and Options for Mitigating Their Effects*, GAO/RCED-97-6 (Washington, DC, December 1996).

oil, compared with the potential economic costs of oil shocks. NEMS was used to perform the study, by assuming higher world oil prices or an oil import fee phased in over a 10-year period. The study found that while growth in oil imports slowed, relative to the *Annual Energy Outlook 1996*[3] (*AEO96*) reference case, absolute levels of oil imports might still rise, depending on the price of oil. Increased domestic oil production was responsible for almost three-fourths of the oil import reduction, while reduced consumption was responsible for the rest of the import reduction. If oil prices were $20 per barrel higher than projected in *AEO96*, the gross domestic product would be reduced by more than $100 billion, and oil imports would be cut by 3.2 million barrels per day by 2005. A review of various indices of vulnerability leads to the conclusion that the U.S. economy will remain vulnerable to oil shocks for, at least, the next 20 years; however, there are some near- and long-term options for mitigating vulnerability, including early use of the Strategic Petroleum Reserve and higher gasoline taxes.

Figure 2. Buildings Electricity Consumption, 1970-2015



History: Energy Information Administration, *Annual Energy Review 1995*, DOE/ EIA-0384(95) (Washington, DC, July 1996). **Projections:** *AEO97* and a projected historical trend.

Electricity Demand in Buildings
Moderator: Steven H. Wade, Energy Information Administration

The objective of this session was to examine projected sources of growth in buildings electricity demand. Given the importance of current electricity issues—industry restructuring and carbon emissions from fossil-fuel generation—the magnitude of electricity growth during the midterm period is critical. Buildings are the largest consumers of electricity; therefore, understanding the projected sources of growth in buildings electricity demand is important. In addition, the composition by end use is projected to change over the projection interval, with significant growth projected for the multitude of end uses covered in the broad category of "miscellaneous." End uses in this category include communications equipment, computer-related equipment (such as local area networks and modems), medical devices, elevators and escalators, televisions and video cassette recorders, television cable boxes, waterbed heaters, and battery chargers for a variety of portable, cordless devices.

Background

Although electricity consumption for buildings shows fairly smooth growth from 1970 to 1996, *AEO97* projects significantly lower growth through 2015 (Figure 2). Penetration of new high-efficiency equipment and lower assumed growth in housing stocks and commercial floorspace are the primary reasons that the projected growth in electricity demand differs from the historical trend.

The miscellaneous category of electricity consumption is a significant source of uncertainty in the projections. Growth in this category has outpaced the major, identified end-use categories (for example, space heating and cooling, water heating, lighting, and refrigeration), and that trend is likely to continue. In formulating the *AEO97* projections, miscellaneous electricity use was considered in aggregate with very general assumptions. Further disaggregation of this category would help to focus the debate over policy options designed to limit energy growth; however, additional information beyond the current EIA surveys would be required. The task will be somewhat more difficult for commercial buildings because of their tremendous diversity of equipment.

Electricity Demand in Households
John Cymbalsky, Energy Information Administration

Over the period 1960 through 2015, electricity has been and is projected to be the fastest growing energy source

[3]Energy Information Administration, *Annual Energy Outlook 1996*, DOE/EIA-0383(96) (Washington, DC, January 1996).

for the residential buildings sector. Within electricity, the category of miscellaneous end uses[4] has the most rapid projected growth, increasing its share of electricity consumption from 32 percent to 48 percent between 1995 and 2015. The difficulty in collecting data on the specific end uses in this category limits the ability to represent it in further detail.

Air conditioning is the largest individual electricity use and is represented in considerable detail. For three building types and the nine Census divisions, the projections consider the size, average efficiency, and average energy consumption of the current stock; future prices of energy; equipment cost and efficiency; further penetration into existing housing; and recent consumer behavior in choosing between cost and efficiency. Both room and central air conditioning, including heat pumps, have a fairly wide range of efficiencies available; however, the average purchased efficiency tends to be near the low end of the range, barely exceeding the minimum Federal standards, indicating that air conditioner purchases are evaluated with high implicit discount rates.[5] Although more efficient air conditioning technologies exist that could result in significant energy savings, they are more costly, with costs often outweighing the benefits even when benefits are evaluated over a long time horizon. With declining real electricity prices, low penetration of these high-efficiency products is projected.

Electricity Demand in Commercial Buildings

Erin Boedecker, Energy Information Administration

Over the period 1970 through 1996, electricity was the primary source of growth in commercial energy consumption, and by 2015 electricity will become the largest source of energy in that sector. Although total energy intensity declines slightly in the *AEO97* projections, electricity intensity grows modestly in the future at a rate less than the historical rate. Among the individually identified end uses, the technology assumptions have varying impacts on energy intensity. Potentially most affected by advanced technologies is lighting, where the adoption of the best available technologies for all new purchases regardless of cost could reduce energy intensity annually by about 2 percent relative to the reference case.

Between 1995 and 2015, miscellaneous electricity consumption from a wide variety of equipment[6] surpasses both lighting and space conditioning, and its energy intensity increases more rapidly through 2015 than all other end uses. Of the building categories, health care is the most intensive in the use of miscellaneous electricity, followed by lodging and food sales, then office buildings. Projected growth rates vary considerably across the building categories, with mercantile / service and food sales showing the highest growth. Determining the areas in the commercial sector where miscellaneous use is concentrated and where growth is expected to occur are the first steps toward learning more about this end use and applying more specific assumptions concerning potential growth.

Miscellaneous Electricity Use in Buildings

Jonathan G. Koomey, Ernest Orlando Lawrence Berkeley National Laboratory Presented by Arthur Rosenfeld, Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy

In the *AEO97* projections, growth in miscellaneous electricity uses far exceeds any other individually identified end use and accounts for more than 90 percent of the growth in carbon emissions. Lawrence Berkeley National Laboratory (LBNL) is developing a “bottoms-up” approach to modeling miscellaneous electricity for the residential sector,[7] categorized by motor loads, lighting, heating, and electronics. Electronics contributed roughly half of the growth between 1976 and 1995, followed by motors and heating. To illustrate changes over time, the top ten energy uses were compared for 1980 and 1995. These uses contributed more than half of the growth in miscellaneous electricity consumption in that period.

A series of shipment trends and forecasts for four specific types of equipment were used to show how different products might contribute to future miscellaneous electricity growth. For example, recent growth in ship-

[4]For example, televisions and video cassette recorders, audio systems, cable boxes and satellite receivers, furnace fans, waterbed heaters, clothes washers, microwave ovens, dishwashers, coffee makers, toaster ovens, security systems, swimming pool pumps, garage door openers, transformers for cellular phones, laptop computers, toothbrushes, and cordless vacuums.

[5]For room air conditioners, the implicit discount rate is 150 percent, for central air conditioning 69 percent, and for heat pumps 30 to 33 percent.

[6]For example, computer communications equipment, such as local area networks and modems, elevators and escalators, medical imaging equipment, telephone equipment, vending machines, automatic doors, and food preparation equipment.

[7]A similar approach for the commercial sector is planned by LBNL for later this summer.

ments of compact stereos and satellite disks cannot be merely extrapolated because of the explosive nature of recent growth, so explicit assumptions concerning their rate of adoption and ultimate penetration are required. To better characterize miscellaneous electricity use and policy options, such as voluntary programs and efficiency standards, further reconciliation of the bottoms-up approach with the EIA Residential Energy Consumption Survey and representations of current and future consumer purchasing behavior and market trends is required.

The Questions We Ask
John A. "Skip" Laitner, Economic Research Associates

Modeling the future involves a study of the past and present. Questions arise as to the validity of extending past behavior and conditions into the future. When markets are undergoing structural changes, modeling past behavior and relationships may no longer be sufficient. For example, modeling future equipment purchase decisions may require more than just replicating current decisions. During the development of the *AEO97* projections, an issue was raised about potential limitations on technology penetrations imposed by the functional form that was then used in modeling residential equipment efficiency choice.[8] As was pointed out, the use of a "bias" term in the choice equation limited the ultimate, potential technology penetration under conditions in which the capital costs of equipment became negligible. To model as wide as possible a range of potential future cases, the recommended changes to the functional form were made to the residential model for *AEO97*.

In the commercial sector, projections of the penetration of energy-efficient lighting systems were compared between *AEO97* and estimates developed by members of the Environmental Protection Agency's (EPA) Green Lights program[9] staff. While agreement was quite close early in the projection interval, by 1997 a rapidly widening gap in energy-efficient lighting opened up. By 2015, *AEO97* projected a slight increase to just over 10 percent, while the EPA projection was over 50 percent. This gap exists, in part, because of differences in the modeling of programs such as Green Lights. NEMS includes an array of available equipment and the required behavior of program participants—for example, adopting retrofits that meet minimum financial hurdles—and lets the model choose the penetration of specific equipment types. EPA's analysis targets specific equipment recently adopted by program participants and extends the results over the program's horizon.

Finally, more emphasis on advanced technology cases in the *AEO* is recommended. A fully integrated technology case with more penetration of high-efficiency equipment than in the reference case is one proposal. Since the *AEO97* high technology cases were not fully integrated, they did not have the same emphasis as the reference case.[10] Additional emphasis on advanced technologies in the *AEO* would heighten awareness of potential energy impacts and provide insight for policy development.

Electricity Restructuring: Preparing for Competition
Moderator: J. Alan Beamon, Energy Information Administration

The objectives of this session were threefold: to discuss the potential effects of competitive pressures in terms of cost reductions and new service options, what consumers might need to take advantage of competitive offerings, and consumer experience in retail access pilot programs that are now being undertaken in several States.

Electricity Restructuring: Strategies and Issues
Margaret Carson, Enron Corporation

Although the pace of change is uncertain, electricity restructuring may lead to significant price reductions. Using evidence from other deregulated industries, including trucking, railroads, airlines, long-distance telecommunications and natural gas, it can be illustrated that prices have fallen by as much as 40 percent over a 2- to 10-year time frame after deregulation. The evidence suggests that the price reductions came from reducing employees and increasing the utilization of equipment. For example, in the telephone industry, the number of employees fell by 23 percent while operating expenses per call declined by 82 percent. Similarly, natural gas pipeline employees fell by an average of 23 percent between 1991 and 1995, while transportation

[8]The ideas were developed in a paper by Stephen J. DeCanio and Skip Laitner entitled, "Modeling Technological Change in Energy Demand Forecasting: A Generalized Approach," *Journal of Technological Forecasting and Social Change*, Vol. 55, No. 3 (in press, 1997).

[9]The Green Lights program enlists voluntary participants to have their existing lighting audited. If retrofitting projects that pass a hurdle rate of 20 percent are found, the participant is required to retrofit within 5 years.

[10]See "Sensitivity of Energy Intensity in U.S. Energy Markets to Technology Change and Adoption" (page ??) for an analysis of integrated technology cases.

rates fell by 17 to 28 percent, depending on the company. It is expected that a wide variety of new value-added services will develop. For example, some firms may specialize in marketing and power aggregation, while others may specialize in billing, metering, and account management services. A large market for demand management services—time-of-use rates, load control electronics in major appliances, etc.—is likely to develop. It is also likely that consumers will have the option of buying all their energy services from a single supplier if they choose to do so.

Getting Ready for Competition
David Moskovitz, The Regulatory Research Project

Although competition may bring many benefits, there could be some bumps in the road unless consumers have the information they need to make informed electricity consumption decisions. Through focus groups in various States, consumers have indicated that they want standard information about electricity prices, fuel mix (types of fuel used to produce the power they are being offered), fixed and variable price components, and emissions. In recent retail pricing experiments consumers were bombarded with marketing claims, and they found it difficult to compare the various offers they received. Standard labels, the electricity equivalent of FDA food labels, could be developed to provide this information, with the goal to "allow informed customer choice to dictate future fuel mix and emissions."

Retail Wheeling Pilots: Lessons Learned
Glenn Reed, XENERGY Incorporated

At this time, a large number of States have initiated or are discussing retail access projects. The results to date indicate that lower prices were the most important factor in consumer decisions to purchase power from a particular supplier. Suppliers marketed very aggressively. Besides low prices, suppliers also marketed their power as green power (from environmentally friendly resources), power from local suppliers you can trust, and power from experienced providers. Each of these themes appealed to some consumers, but only if they were also offered with fairly low prices.

In general, the pilot projects have been successful. They have lowered electricity prices, and there have been no significant power outages. However, caution should be used in interpreting these results. The pilot programs have been extremely small, and participation has been voluntary. The questions of whether electricity will be treated as a commodity versus a value-added product and whether there will be operational problems with full retail access have yet to be answered.

Natural Gas Supply
Moderator: Scott B. Sitzer, Energy Information Administration

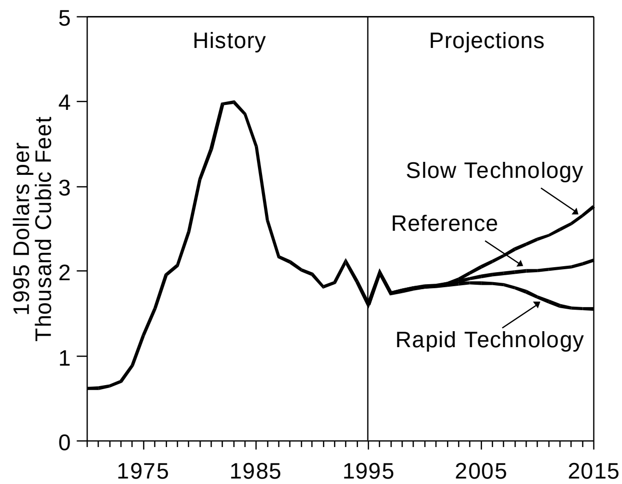
The objectives of the session were to compare midterm trends in natural gas prices and production as projected in AEO97 *with those in other reputable forecasts; to discuss the effects of technological progress on natural gas prices and production, relating this discussion to the* AEO97 *projections; and to discuss the importance of geology, i.e., resource considerations, with respect to natural gas prices and production, again relating this discussion to the* AEO97 *projections.*

Natural Gas Supply Forecasts
James M. Kendell, Energy Information Administration

In the *AEO97* reference case, the wellhead price of natural gas in 2015 was $2.13 per thousand cubic feet in real 1995 dollars. Technology plays an important role in the economic viability of natural gas resources and is represented in the oil and gas supply module of NEMS through the assumption of continuous improvement in the technology used to discover, develop, and extract natural gas. *AEO97* also included two cases that varied the technology assumptions for oil and gas. In the rapid technological growth case, the wellhead natural gas price was $1.55 per thousand cubic feet in 2015, while the projection in the slow technological growth case was $2.77 per thousand cubic feet (Figure 3). The primary difference among these three cases was the pace of technological improvement, with higher or lower rates of technological progress leading to prices that were lower or higher, respectively, than those in the reference case.

The *AEO97* price projection for natural gas in 2015 was higher than forecasts released by the Gas Research Institute (28 percent) and the American Gas Association (AGA) (1 percent) but lower than projections from DRI/McGraw-Hill (16 percent) and the WEFA Group (17 percent). The EIA projection was also lower (25 percent) than that of the *Oil and Gas Journal* (*OGJ*) through 2005, which is the latest *OGJ* projection available. Price and production forecasts through 2015 for all these organizations are presented in Table 2. Determinants of the *AEO97* projections included the economically recoverable resource base of natural gas, which increases from 1,139 trillion cubic feet in 1990 to 1,561

Figure 3. Lower 48 Natural Gas Wellhead Prices in Three Cases, 1970-2015



Sources: **History:** Energy Information Administration, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996). **Projections:** *AEO97*, Tables A14 and F8. **Note:** Prices are converted to 1995 dollars.

trillion cubic feet by 2015 in the reference case; increases in total successful wells drilled from about 14,000 in 1995 to about 28,000 in 2015; lower 48 natural gas reserve additions rising though 2008, peaking at 25.8 trillion cubic feet; and natural gas consumption growth to 30.2 trillion cubic feet by 2015. Total natural gas production was projected to rise to 26.1 trillion cubic feet by 2015, stimulated by rising wellhead prices, the relative abundance of natural gas resources, and improvements in technology. EIA's production estimate in 2015 was the highest of those examined. Although *OGJ* was generally higher than EIA, its forecast horizon extended only through 2005.

Representing Technological Progress in Oil and Gas Supply Models

Vello A. Kuuskraa, Advanced Resources International, Inc.

From a technological perspective, the outlook for natural gas supply has changed over the past two decades. Forecasters have gone from predicting a future of

Table 2. Comparison of Natural Gas Price and Production Forecasts

Forecast	1995	2000	2005	2010	2015
Production (Trillion Cubic Feet)					
AEO97	18.49	20.54	22.66	24.25	26.10
DRI	17.97	20.30	21.24	22.01	22.94
WEFA	19.27	19.51	21.01	21.28	20.41
AGA	18.75	20.77	21.60	23.01	24.39
GRI	18.26	19.44	21.07	23.57	25.90
OGJ	19.51	21.30	22.95	—	—
Price (1995 Dollars per Thousand Cubic Feet)					
AEO97	1.61	1.82	1.94	2.01	2.13
DRI	1.59	1.90	2.15	2.41	2.54
WEFA	1.68	2.10	2.26	2.42	2.57
AGA	1.59	2.10	2.10	2.10	2.10
GRI	1.56	1.76	1.68	1.66	1.66
OGJ	1.55	2.14	2.58	—	—

— = not available.

Sources: ***AEO97*:** Energy Information Administration, *Annual Energy Outlook 1997*, DOE/EIA-0383(97) (Washington, DC, December 1996). **DRI:** DRI/McGraw-Hill, *World Energy Service: U.S. Outlook, Fall-Winter 1997*. **WEFA:** The WEFA Group, *U.S. Energy Report* (Spring-Summer 1996). **AGA:** American Gas Association, *1996 AGA-TERA Base Case* (August 1996). **GRI:** Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1997 Edition (August 1996). ***OGJ*:** "Oil Industry Outlook," *Oil and Gas Journal* (August 1996, updated March 1997).

scarce resources, high costs, and high future prices to one of a rich and diverse resource base, much lower costs, and more moderate price increases. The reasons for the change included an expansion of the resource base because of advances in exploration and recovery technology, technology-based increases in efficiency, and decreases in costs. The expansion of the resource base was mostly due to new technology-based plays, particularly coalbed methane, deepwater resources greater than 1,000 feet, and Antrim shale. A major source of increase in the United States Geological Survey (USGS) estimate of natural gas resources has been the increased estimate of inferred reserves in existing fields, which grew from 93 to 291 trillion cubic feet between 1989 and 1995. EIA's rates of resource expansion for conventional onshore natural gas were probably on the high side in *AEO97*, while those for unconventional gas resources were possibly too low.

Improvements in the success rates for new field discoveries have occurred, primarily as the result of advanced, low-cost 3-D seismic technology and other geologic tools. There have also been improvements in exploration efficiency for discovering new fields, and exploration-based gas reserves per exploratory well have improved from 2.9 billion cubic feet per well in the 1981 to 1985 period to 7.4 billion cubic feet per well in 1994. Considerable research and development (R&D) is also underway in the areas of play selection, stimulation technology, and horizontal wells.

Lower costs for exploration and recovery arise primarily from economies of scale with large drilling programs and from technology-based cost reduction. Opportunities for further cost reduction include increased slimhole drilling and accelerated application of best practices. The decline of drilling costs by 2.1 percent per year in the *AEO97* reference case is probably too high. Private sector R&D has been halved since 1990-91 and a resultant future slowdown of technological progress is quite possible. Continued R&D is essential to technology improvement, with potential price impacts as seen in the *AEO97* rapid and slow technology cases.

Domestic Natural Gas in the Next Twenty Years: Does Geology Matter?

Joseph P. Riva, Consultant

In contrast to the pessimism of projections made in the mid-1970s, EIA and others appear optimistic. There may be reason for more pessimism regarding the future, including the facts that new fields are rare and that the resource balance implies future production difficulties for the lower 48 States. In the last 12 years, gas production has risen at the expense of proved reserves, with the help of drilling more wells that, on average, produce less gas. Total reserves are down by 4 percent, total production is up by 4 percent, total producing wells are up by 33 percent, and average production per well is down by 20 percent. In addition, although production in the Gulf Coast has been constant, production in regions other than the Gulf Coast is down, and the lower 48 average reserves/production (R/P) ratio is 9:1, down from 11:1 in the mid-1980s.

Considering EIA's projections for the next 20 years, if a constant R/P ratio is assumed, reserves in 2015 must reach 524 trillion cubic feet, implying that 198 trillion cubic feet of reserve additions from new fields would be required over the next 20 years. This implies that the new field discoveries added per year would have to be seven times the average for the past 10 years. Also, more undiscovered recoverable resources would be required than are now believed to remain onshore, according to the most recent USGS resource assessment. Large discoveries in the outer continental shelf will be necessary to maintain current production levels, a prospect that may be optimistic.

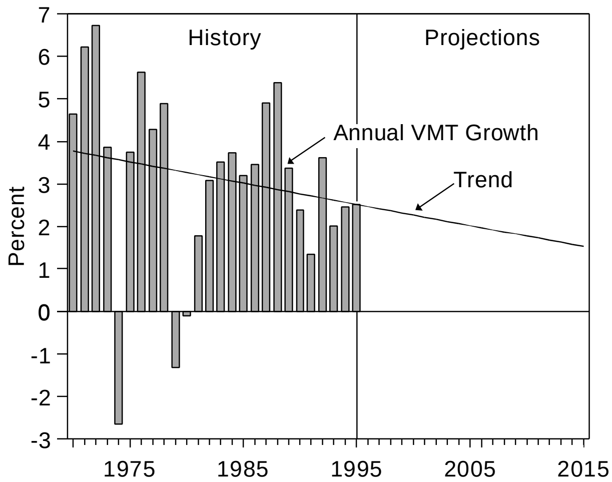
Transportation Demand and Personal Highway Travel

Moderator: Barry N. Cohen, Energy Information Administration

Personal highway travel has increased steadily for many decades. The energy crisis years—1973 to 1974 and 1979 to 1980—are the only exceptions to positive growth in vehicle-miles traveled (VMT) since World War II; however, the rate of the increase in VMT has slowed (Figure 4). During the 1970s, annual growth rates above 4 percent were common, and during the 1980s rates were generally more than 3 percent. In the 1990s, personal highway VMT has increased at an average annual rate of about 2.4 percent, and the AEO97 *projects an average annual growth rate of 1.4 percent through 2015. While EIA is not alone in presenting estimates of VMT growth that are below 2 percent,*[11] *each of the speakers in this session has previously argued for rates of VMT growth substantially higher than EIA's. The session focused on identifying for further consideration key factors that may sustain a VMT growth rate of 2 percent or above for several decades to come.*

[11]Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand*, 1997 Edition (August 1996); DRI/McGraw-Hill, *World Energy Service: U.S. Outlook, Spring-Summer 1996* (April 1996); American Petroleum Institute, *U.S. Highway Fuel Demand: Trends and Prospects* (November 1996).

Figure 4. Annual Growth in Personal Travel, 1970-2015



Source: U.S. Department of Transportation, Federal Highway Administration, Table VM-1, “Sum of Categories Passenger Cars, Motorcycles, and Other 2-Axle 4-Tire Vehicles, Annual Reports.”

Potential for Growth in Vehicle Travel

David L. Greene,
Oak Ridge National Laboratory

It appears very likely that highway vehicle travel will grow at rates in the vicinity of 2 percent per year for the next two to three decades. Such projections can be inferred from fairly conservative assumptions about population and economic growth and by extrapolating trends in travel behavior. Although slowing population growth and the aging of the U.S. population will tend to hold down future travel growth, there is substantial room for future expansion.

Current differences between male and female travel behavior may hold the greatest potential for future travel expansion. Passenger vehicle travel forecasts can vary, based on different assumptions concerning the rate at which male and female driving and travel behavior converge. In a rapid male-female convergence case, both the miles traveled per female of every age group and the miles driven by females per mile traveled are assumed to converge on the rates for males in the same age group, at the rate of 5 percent of the current difference per year. In this case, by 2020, females travel virtually the same miles as males and drive just as frequently when they travel. As a result, light-duty vehicle travel increases at an average rate of 2.3 percent per year through 2020. If it is assumed that there is no convergence at all and that females continue to travel about 80 percent as many miles as males and drive about 75 percent as often, the rate of travel growth falls to 1.6 percent per year.

Prospects for Growth in Personal Travel

Don Pickrell,
Volpe National Transportation Systems Center

Passenger vehicle travel growth over the next few decades will be lower than growth in the past two decades, but how much less is uncertain. Growth in certain components of vehicle travel, such as the percent of the population licensed to drive and vehicles per licensed driver, has slowed in recent years as the levels have increased. In 1995, 88 percent of the driving-age population was licensed to drive, and there was more than one passenger vehicle per licensed driver. Licensure rates much above current levels would require higher licensure rates among octogenarians.

The rate of future population growth itself poses the greatest element of uncertainty. Available VMT forecasts typically focus on the Bureau of the Census middle series estimates of future population; however, the Bureau provides a wide range of population forecasts based on alternative immigration trends that should be investigated. Other important elements of uncertainty include future trends in the driving behavior of retirees and non-work-related trip lengths.

Factors Affecting Future Vehicle Miles Traveled

John German,
U.S. Environmental Protection Agency

Emerging travel trends bolstering VMT growth are difficult to identify or access on the basis of historical data; yet, they are crucial to understanding future highway travel demand. Important factors that require additional attention include: land use patterns with residences further from central cities; societal growth patterns increasing the desire for, and dependence upon, personal mobility; infrastructure and zoning laws; and growth in driving by retirees, women, and immigrants. In the coming decades, the increasing share of the population over the traditional retirement age will make assumptions about the travel behavior of retirees extremely important to overall VMT forecasts. While the Department of Transportation’s Nationwide Personal Transportation Survey continues to show both male and female retirees driving less than younger age groups, the percentage difference has declined in recent years and will likely decline in the future.

Electricity Prices in a Competitive Environment

Moderator: Robert T. Eynon, Energy Information Administration

The objective of the session was to discuss what cost elements will be included in competitive electricity prices and how the costs of maintaining system reliability will be computed.

Electricity Prices in a Restructured Electric Power Industry

Arthur S. Holland, Energy Information Administration

Under cost-of-service regulation, prices to consumers reflect both production cost and investment costs. Under competition, the prices will be based on marginal operating costs and the relationship between supply and demand. The difference between competitive prices and average costs is a measure of existing "stranded costs" based on past investments in assets as well as purchased power and fuel supply contracts.

Competitive prices may rise above marginal costs during periods of high demand if it approaches the limits of generating capacity. The degree to which prices rise above marginal costs is expected to be consistent with consumers' willingness to pay to avoid an outage. Premiums above marginal costs may encourage suppliers to invest in new facilities when needed to meet the level of reserves that is consistent with consumers' willingness to pay. The volatility of competitive prices will give consumers the signals needed to adjust their consumption patterns. More responsiveness on the part of consumers causes competitive prices to decline, which in turn raises the level of stranded costs. Under competition, prices for electricity could decline by 6 to 12 percent.

Blackout Costs

Vance C. Mullis, Southern Company

The notion of optimal reserve margin must take into account that totally eliminating the prospect of a blackout is not in the best interest of consumers, because the cost of such assurances is prohibitively high. On the other hand, frequent disruptions are costly to consumers. In order to strike a balance it is necessary to determine the value of lost load as a measure against which investments in reserve capacity can be evaluated.

Surveys have been conducted to provide estimates of how consumers in various groups value lost electricity as a measure of their willingness to pay for reliability. Because surveys do not necessarily represent how customers would respond in the marketplace, they have limited usefulness. When customer responses to surveys are averaged, the response of outliers can unduly affect the results. Systems need to plan on minimizing the unserved energy times the value of unserved energy and the cost of capacity that provides the reliability. Reserve margins are unlikely to decline precipitously in a competitive environment. Consumers who value reliability will make the investments to assure that their needs are met, while other consumers will forgo such expenses and accept lower levels of service.

Pricing Transmission and Generation at the Margin

Robert J. Graniere, National Regulatory Research Institute at Ohio State University

There is concern that consumers will not enjoy electricity prices as low as possible if market power exists in either generation or transmission. An independent system operator (ISO) for the transmission grid is needed to assure competition. Although the exact role of an ISO has not been defined, it will have a substantial role to play.

An ISO is a natural monopoly and should be cost-of-service regulated. By contrast, generation should be competitively procured and should be accessible directly by customers through bilateral contracts. When transmission lines are underutilized, prices will be the lowest possible, and there will be no opportunity to exercise market power. When transmission constraints exist, power availability will be reduced geographically, and market power can be exercised by suppliers at the margin. When generation capacity is constrained, market power will emerge in spot markets.

It is the role of the policymaker to deal with both generation and transmission constraints in order to assure that power is delivered to designated local areas. Prices should reflect the reliability costs of delivering power. Methods should be developed for provision of interruptible services, price-differentiated services, and allocation of shortages. These policies will help to mitigate market power. It is the role of a regulated transmission market to provide reliability-differentiated prices. It is, however, inevitable that market power will exist at the margin. It is the role of the regulator to intervene in generation and transmission to assure free wholesale and retail markets.

Evolution of the Power Marketing Industry
Russell N. Henn, LG&E Power Marketing, Inc.

The impetus for competitive power markets was the Energy Policy Act of 1992 and the subsequent Federal Energy Regulatory Commission Orders 888 and 889, which opened up the transmission grid and established a basis for pricing transmission services. As a result, 350 licensed power marketers have become players. They are made up of financial/commodity traders, independent power producers, natural gas traders, entrepreneurs/aggregators, and affiliates of electric utilities. Between 1995 and 1996, sales grew from $0.5 billion to $4.6 billion, and they are projected to increase to $40 billion by 2002.

The three largest firms in this market are Enron, Duke/L. Dreyfus, and LG&E Power. These firms represent almost half the power marketers. The move toward restructuring is accelerating, as evidenced by State and Federal initiatives. There are pilot programs in retail markets. Several States have plans to have open retail markets by 1998, and more States are likely to have open retail markets over the next 5 to 8 years. Marketers will offer new services such as the combined marketing of gas, coal, and electricity. The impacts on consumers are likely to be price reductions. EIA estimates of price reductions of 6 to 12 percent seem reasonable.

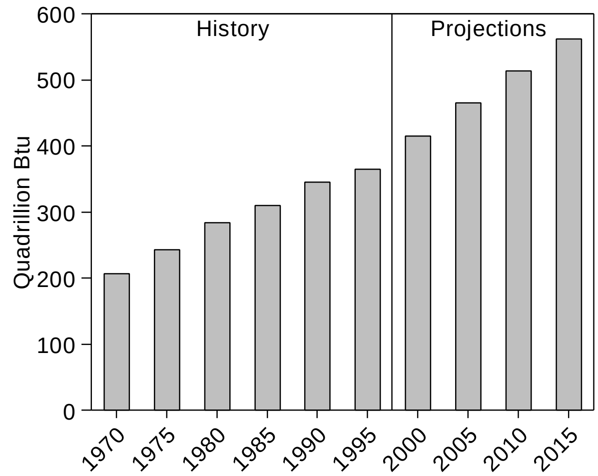
International: Energy Demand in Developing Countries
Moderator: Arthur T. Andersen, Energy Information Administration

The speakers in this session addressed three interrelated questions. First, are there reasons to question the continued prospect for growth in energy demand in the Asian Pacific Region? Second, who will supply oil to Asia as demand outstrips indigenous production capability? Finally, with world oil demand likely to surpass 100 million barrels per day by 2015, are we approaching a threshold of resource exhaustion?

Background

Global energy demand is rising rapidly. EIA's *International Energy Outlook 1997*[12] projects an increase of 200 quadrillion Btu in worldwide demand between 1995 and 2015 (Figure 5). This change is equivalent to total world energy consumption in 1970. A major part of demand growth occurs in developing countries, where sustained economic expansion and rising per capita income spur increased use of energy, especially electricity and petroleum products. Among developing areas, economic expansion in the Asia Pacific region is most notable. In this region, the rate of economic growth has exceeded 5 percent over the past decade, and energy demand growth has nearly matched that rate. As a consequence, the Asian countries' share of world energy demand rose from 20 to 27 percent between 1985 and 1995 and will continue to rise in the future. Developing countries of Asia, including especially China and India, are expected to account for half the total growth in world energy demand over the next two decades.

Figure 5. World Energy Consumption, 1970-2015



Sources: **History:** 1970-1975: Energy Information Administration (EIA), Office of Energy Markets and End Use, International Statistics Database. 1980-1995: EIA, *International Energy Annual 1995*, DOE/EIA-0219(95) (Washington, DC, December 1996). **Projections:** EIA, *International Energy Outlook 1997*, DOE/EIA-0484(97) (Washington, DC, April 1997).

Asian Energy Demand
Dennis Eklof, Cambridge Energy Research Associates

Although there are issues of uncertainty regarding economic and energy growth in Asia, economic growth is likely to average about 5 percent—more than twice the rate of growth projected for the United States and Western Europe. Although growth in China is expected to slow, it is still expected to exceed the average for Asia as a whole. Energy demand growth is projected to nearly match the rate of economic expansion. Rising standards of living, which increase the use of appliances, air conditioning, and personal transportation,

[12]Energy Information Administration, *International Energy Outlook 1997*, DOE/EIA-0484(97) (Washington, DC, April 1997).

foster increased energy use. In addition, the expanding availability of electricity in the region completes the process of electrification. However, the substantial political uncertainty that exists within the region might undermine economic growth prospects. The sources of uncertainty are country specific and varied. A key challenge faced by China, for example, is the manner in which it will achieve reform for state-owned enterprises.

Asian Oil, the Middle East, and Energy Security Problems [13]
Fereidun Fesharaki, East-West Center

In reviewing oil demand and supply within the Asia Pacific region, a key trend is rising import dependency for the region. Oil plays an important role in the regional energy demand and supply, especially in economies outside China and India. Even in China and India, oil is the key to economic development, although coal dominates the energy scene. Regional oil demand is projected to grow to 21.4 million barrels per day in 2000, 25.3 million barrels per day in 2005, and 29.4 million barrels per day by 2010. This translates into a 4-percent average annual growth rate of oil demand over the remainder of the decade and 3.2 percent for the period 2000 to 2010, averaging 3.5 percent for the entire forecast period from 1995 to 2010.

Increases in regional crude oil production are expected to be moderate over the next 5 years, reaching 7.2 million barrels per day in 1997 and peaking at 7.3 million barrels per day in 2000. Additions to crude oil production before 2000 are expected to come mainly from India, China, and Australia, while production in Indonesia and Malaysia declines. After 2000, the East-West Institute base case regional forecast projects a slow decline to crude oil production totaling 0.7 million barrels per day in 2010.

The Asia Pacific region is a net importer of both crude oil and refined products. The deficit for crude oil is much larger than the deficit for refined products because of the huge refining capacity built in the region. Crude oil consumption in the Asia Pacific region is forecast to be 18.6 million barrels per day in 2000, 23.2 million barrels per day in 2005, and 26.9 million barrels per day in 2010. As the region's own crude oil production is flat, imports of crude oil will increase. By 2000, imported crude oil from outside the region is projected to be 11.3 million barrels per day, up from 8.5 million barrels per day in 1995, reaching 16.3 million barrels per day by 2005. By that time, crude oil from the Middle East and other parts of the world would account for 64 and 6 percent, respectively, of the total regional supply, with indigenous production supplying the balance.

Resource Constraints and World Oil Supply
Edward D. Porter, American Petroleum Institute

Given the large prospective gains in oil demand, there are a number of supply-side issues regarding oil. Despite high rates of demand growth, the prospect of resource exhaustion in the next half century is unlikely, provided technology is allowed to be applied in resource-rich producing areas.

Known reserves are not a good indication of potential future oil supply. Reserves should be viewed as an inventory concept, indicating the portion of the resource base that is developed to support near-term production requirements. Forecasts of imminent shortage based on the current use of developed reserves have continually been proven wrong. Views on the adequacy of oil production potential must focus more on resource potential rather than on reserves. Over time, resource potential has grown enormously, in part because resources hitherto unknown have been uncovered throughout the world and in part because technology has improved our ability to increase recovery from known resources. Given recent trends in resource assessment, which have consistently involved upward revisions, world oil requirements that grow at 2 percent per year are supportable for upwards of a century.

Import dependence equal to 77 percent of overall demand is projected by 2010. Most of the increased dependence will involve imports from the Middle East. As Asian countries increase oil use and reliance on imports, substantial changes in business and political relationships between Asian and Middle East countries can be anticipated.

[13]Fereidun Fesharaki and Kang Wu, "Asia-Pacific Oil Market in the Global Context," East-West Center (Honolulu, HI, March 1997).

Coal Supply and Distribution

Moderator: Edward J. Flynn, Energy Information Administration

The objectives of this session were to discuss the following issues concerning the coal market: first, trends in coal productivity; second, potential impacts of rail mergers on distribution patterns; and, finally, trends and projections for coal supply patterns and prices.

U.S. Coal Mine Production and Productivity: How Did We Get Here and Where Are We Going?

Alan K. Stagg, Stagg Engineering Services, Inc.

Several specific events have influenced both coal production and productivity during the past 25 years. The major events in the 1970s and 1980s included the oil price shock and the consequent coal boom, new mine investment, recession, excess production, industry restructuring and consolidation, and changes in labor attitudes. Entering the 1990s, the passage of the Clean Air Act Amendments of 1990 led to the adoption of compliance strategies by electric utilities that have caused ongoing shifts in supply sources—largely to the West—and coal distribution patterns in order to meet needs for low-sulfur coal.

Continued improvements in equipment, including increasingly sophisticated electronics, improved reliability, and larger size and capacity, have contributed to substantial gains in productivity. Unit production costs have been driven lower by competition between coal-producing regions and by alternative fuels such as natural gas. Changes in worker and management attitudes and changes in work rules have also been significant factors in achieving productivity gains. It is projected that excess productive capacity will continue to be the single most important factor in determining coal selling prices, and that producers must continue to achieve productivity gains if they are to survive.

Our Look from the Rail Carrier's Perspective

Timothy J. Gannon, R.L. Banks & Associates, Inc.

Substantial consolidation in the major U.S. rail systems has occurred over the past 25 years, and there are prospects for further consolidation in the post-1996 period. Coal's share of total U.S. rail shipments has doubled on a tonnage basis, increasing from approximately 20 percent in 1971 to nearly 40 percent for Class I railroads in 1995. Coal contributes more than 21 percent of total freight revenue. Indicative of changes in the rail systems are the merger that formed the Burlington Northern & Santa Fe Railway and the combination of the Union Pacific Railroad and Southern Pacific. There is the potential for future mergers subsequent to the Conrail acquisition by the Norfolk Southern Corporation and the CSX Corporation, which is now in progress.

Coal Industry Trends and Projections

Richard Newcombe, Energy Information Administration

Between 1990 and 1995, there were a number of changes in the coal industry in terms of industry structure, productivity, and price levels. Most historical trends are projected to continue at a moderating pace in the *AEO97* projections. Trends that are expected to continue include a declining population of mines by 200 to 300 mines per year, increasing labor productivity, and declining minemouth prices. These trends will be reinforced by compositional effects, as more productive, lower cost western mines continue to increase their share of the national coal market at the expense of eastern coalfields.