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ANNUAL OUTLOOK FOR U.S. ELECTRIC POWER 1986

Energy Information Administration
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ANNUAL OUTLOOK FOR U.S. ELECTRIC POWER 1986

Energy Information Administration
Office of Coal, Nuclear, Electric and
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U.S. Department of Energy
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Preface

Section 205(a)(2) of the Department of Energy Organization Act (Public Law 95-91) requires the Administrator of the Energy Information Administration (EIA) to carry out a central, comprehensive, and unified energy data information program. EIA's responsibility is to provide timely, high-quality information and to perform objective, credible analyses in support of deliberations by both public and government decisionmakers.

Electricity is one of the major areas of interest for EIA. Electricity use plays a large and growing role in the U.S. economy; its use continues to increase in every end-use sector. These increases have occurred despite rising prices and growing emphasis on energy conservation, over a period when total U.S. energy consump-

tion has declined. Furthermore, U.S. electricity use is projected to continue increasing, capturing a much larger share of U.S. energy markets.

The *Annual Outlook for U.S. Electric Power 1986* includes summary information on the ownership structure of the U.S. electric utility industry, a description of electric utility regulation, and identification of selected factors likely to affect U.S. electricity markets from 1985 through 1995. This Outlook expands upon projections first presented in the *Annual Energy Outlook 1985*, offering additional discussion of projected U.S. electricity markets and regional detail. It should be recognized that work on the *Annual Energy Outlook 1985* had been completed prior to the sharp reductions in world oil prices experienced early in 1986.

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Executive Summary

Electricity is vital to virtually every aspect of the U.S. economy and its role is projected to expand over the next decade. This *Annual Outlook for U.S. Electric Power 1986* describes the structure and regulation of the U.S. electric utility industry and provides projections of major electric utility market characteristics through 1995. It also describes factors likely to affect those markets over the forecast period, including extending the service life of existing generating plants, increasing bulk power transfers, and the possible role of new generating technologies.¹

Structure and Regulation of the U.S. Electric Utility Industry

The U.S. electric power industry is a combination of private, Federal, cooperative, and public nonprofit organizations. Private investor-owned utilities (IOU's) dominate the industry, accounting for about three-fourths of capacity, generation, number of customers, and sales to ultimate consumers. Other ownership groups play secondary roles. Federal power ranks second in capacity and generation, while municipal utilities and cooperatives rank second in number of customers and third in volume of sales to ultimate consumers.

The electric utility industry is regulated at both the Federal and State levels. Economic regulation of investor-owned utilities (IOU's) is based on the importance of reliable and economic electric power to the public interest and the practice of granting exclusive franchises under the concept that electric utilities are "natural monopolies." Regulation is used to limit IOU monopoly profits and encourage efficiency. State regulatory authorities establish retail rates for IOU's, review their operating practices, and generally must authorize construction of generation, transmission, and distribution facilities. Federal economic regulation of IOU's encompasses rates and terms for wholesale elec-

Hoover Dam, one of America's most famous structures, celebrated its 50th year in 1985.

tricity sales among utilities, where considered to be in interstate commerce, and the oversight of electric holding companies. Generally all electric utilities, however owned, are subject to Federal regulations concerning air and water quality and the protection of wildlife, must obtain Federal licenses for hydroelectric and nuclear generating facilities, and must comply with Federal laws requiring power exchanges with qualifying small power production and cogeneration facilities. However, Federal utilities do not require licenses to construct or operate hydroelectric facilities.

¹For a description of the history of the U.S. electric power industry, its operations, and generation technologies, see Energy Information Administration, *Annual Outlook for U.S. Electric Power 1985*, DOE/EIA-0474(85) (Washington, DC, August 1985).

Table ES1. Projected Average Annual Growth Rates of U.S. Electricity Under Alternate Economic Growth Cases, 1985-1995 (Percent)

	1985 ^a -1995		
	Low	Base	High
Electricity Sales	2.5	2.7	2.9
Gross National Product	2.4	2.8	3.2
Nonelectricity Energy Consumption	-0.1	0.2	0.6
Ratio, Electricity to GNP Growth	1.0	1.0	0.9
Ratio, Electricity to Nonelectricity Energy Growth ^b	-25.0	13.5	4.8

^a 1985 values are estimates; actual values, not available during preparation of this analysis, can be obtained from the **Annual Energy Review 1985** (May 1986).

^b Negative ratios occur when nonelectricity energy consumption declines while electricity sales increase.

Source: Energy Information Administration, **Annual Energy Outlook 1985** (February 1986).

Outlook for Electric Power, 1985-1995

This Outlook focuses and expands upon the energy projections first described in the *Annual Energy Outlook 1985* (AEO), presenting a range of projections for electricity supply, demand, and prices. Both national and regional projections are provided, although the regional projections are inherently more uncertain. EIA projects moderate growth of U.S. electricity demand from 1985 through 1995, at about the overall rate of U.S. economic growth. The projected base case average annual electricity demand growth rate of 2.7 percent over that period is greater than the 2.1 percent average annual growth rate from 1980 through 1984, but well below historical rates. Electricity demand growth is expected to vary considerably by region, from a low of 2.1 percent a year in the New York/New Jersey region to a high of more than 3.3 percent a year in the North Central, Northwest, and Western regions.

Projected 10-year demand growth at no more than the Gross National Product (GNP) growth rate marks a departure from the 1985 forecast and also from historical experience. Whereas in the past industrial electricity demand was expected to grow more rapidly than GNP, in this forecast it is projected to grow less rapidly, at an annual average rate of 2.6 percent. This slowdown is attributed both to expected continued gains in industrial energy conservation and to slowed overall rates of growth of energy-intensive industries, such as primary metals, chemicals, and stone, clay, and glass.

Cases differing from the base case, i.e., the lower and higher (than base case) economic growth cases, suggest that electricity demand from 1985 through 1995 may not be fully responsive to changes in the overall rate of economic growth. Assumed differences of plus/minus 0.4 percent in the economic growth rate result in plus/minus 0.2 percent changes in the same direction for the growth rate of electricity demand.

Rather than the observed historical growth at least equal to overall economic growth, electricity demand is projected to lag slightly behind economic growth except under slower economic growth conditions, as a result of reduced rates of industrial electricity demand growth.

Although electricity consumption is expected to grow no faster than GNP, it is projected to grow more rapidly over the period than nonelectricity energy consumption (Table ES1). More than 85 percent of the increase in total U.S. energy use by 1995 is attributable to increased energy use by electric utilities. Despite high conversion losses from other primary forms of energy to electricity (about 3 input energy units per electricity output unit), electricity as a delivered service is increasingly preferred over other energy sources for its convenience, versatility, and price.

The shares of electricity consumption among the three major end-use sectors--residential, commercial, and industrial--are expected to remain essentially constant over the period, with the residential share remaining at about 34 percent, commercial at about 29 percent, and industrial at about 37 percent. However, in all three sectors, the share of all energy use attributed to electricity is expected to increase.

Real electricity prices are projected to increase slightly through 1987 and then decline by 1995 to about 8 percent below 1985 levels, primarily as a result of declining capital costs per unit of electricity. Capital costs are projected to decline for two reasons: first, existing capacity is being used more extensively, spreading its fixed cost over a greater output, and second, depreciated capacity is projected to be removed from the rate base more rapidly than new capacity is added, lowering the value of total capital stock and thus lowering capital costs per unit of output. On the other hand, fossil-fuel costs are projected to increase later in the period, partially dampening the projected decline in electricity prices, as fossil-fueled generating capacity is used more extensively.

Together, coal-fired and nuclear generation are projected to provide three-fourths of electricity generation. Nuclear power is expected to remain in second place behind coal, a rank first achieved in 1984, while the combined share of oil and natural gas generation remains about 15 percent of all generation. Changes in the rate of economic growth significantly affect the shares of total generation provided by oil and natural gas. In the low economic growth case, in 1995 oil and gas provide 14 percent of total generation, whereas in the high economic growth case they provide almost 17 percent.

Generating capacity is projected to grow at an average rate of 1.2 percent a year, as fuller utilization of existing capacity meets most of the projected growth in electricity demand through 1995. More than 116 gigawatts of new generating capacity are projected from 1985 through 1995: 99 gigawatts are planned or under construction by utilities; an additional 17 gigawatts of combustion turbine capacity are estimated by EIA as needed after 1989 to meet expected demand growth. Rates of economic growth higher than the base case can be expected to require further capacity additions beyond current plans; rates of growth lower than the base case would reduce additional capacity requirements. Of planned capacity additions, 46 gigawatts are new coal-fired capacity and almost 41 gigawatts are nuclear plants. Planned capacity additions decrease rapidly after 1988.

Imported electric power is an important and growing source of electric power in some regions, particularly in the New England, New York/New Jersey, and North Central regions. Electricity imports, primarily from Canada, are projected to increase from 1.8 percent of U.S. electricity demand in 1985 to almost 2.7 percent of U.S. electricity demand by 1995. These

imports may reduce the need for additional new generating capacity in some regions over the forecast period.

Other factors may also affect electric power markets over the forecast period. These include extending the service life of coal-fired power plants, increased bulk power transactions, and the introduction of new technologies. High construction and financing costs and environmental and siting constraints, coupled with projections of low electricity load growth, discourage construction of new power plants. Many utilities have begun research and planning programs to upgrade and refurbish their older coal-fired units to improve their efficiency and to extend their life as an alternative to new plant investment. Plant upgrading and life extension may become an integral part of electric utilities' operations and maintenance systems as a means to lower electricity prices.

Existing capacity may also be used more extensively in the future as a result of increased bulk power transactions. Increasing such transactions may reduce the use of higher cost oil- and natural gas-fired capacity and the need to construct some new generating capacity. However, current transmission system capacity limits the ability to effect some transactions. In the longer run, local demand growth may absorb much of the capacity currently available for bulk power sales.

Finally, some newer technologies may be positioned for commercial use in the 1990's. All are either powered by low-cost or renewable energy sources or are designed to lower electricity costs by changing demand or supply conditions. The technologies are also designed to respond to a wide variety of size requirements. These technologies may increase the flexibility of the electrical system in supplying U.S. electricity needs in the 1990's.

1. The Structure of the U.S. Electric Utility Industry

Ownership Structure

The U.S. electric power industry is a combination of private, Federal, and public nonprofit organizations.² The distribution of capacity, generation, revenue, and sales differs widely among ownership groups. Different ownership groups have different goals, organizational characteristics, and financing methods. Private investor-owned utilities (IOU's) dominate the U.S. electric utility industry, historically serving large consolidated markets where economies of scale afforded the lowest prices. Federal, municipal, cooperative, and other publicly owned utilities play a secondary role. Where markets were small, the access of local governments or nonprofit organizations to government capital markets or to preference in purchase of less expensive Federal power allowed municipal, cooperative, or other publicly owned utilities to predominate. In some instances social preference for economic reform, local control, conservation, or government or utility reform has led to public ownership of electric utilities.

Investor-Owned Utilities

Investor-owned utilities (IOU's) account for about three-quarters of all U.S. electric utility capacity, generation, sales, and revenue (Table 1). In 1984, ultimate consumers paid an average of 6.50 cents per kilowatthour (kWh) for privately produced power (Table 2). IOU's are privately owned, profit-seeking businesses granted service monopolies in certain geographic areas and obliged to serve all customers. Their fundamental objective is to produce a return for their investors. Nevertheless, as franchised monopolies, IOU's are required to charge reasonable prices (based on efficiently incurred costs), to charge similar prices to similar customers, and to give customers access to services under similar conditions. Most IOU's provide basic services of generation, transmission, and distribution of electricity. They operate in all States except

Nebraska; Hawaii is the only State in which all electricity is supplied by private power companies.

Most IOU's are organized as corporations and are highly capital-intensive. To finance their continued development, IOU's rely on internally generated funds, issue common and preferred stock, and sell long-term debt. Internally generated funds are composed of retained earnings, depreciation, deferred taxes, and investment tax credits, of which depreciation is the most significant. At the end of 1984, 41 percent of IOU's capital was attributable to common stock, 10 percent to preferred stock, and 48 percent to long-term debt.³

There are major exceptions to these general patterns. Holding companies are major utility businesses that do not generate, transmit, or distribute electricity; instead, they control (hold) groups of operating companies. Nine electric utilities are currently organized as holding companies under the Public Utility Holding Company Act of 1935.⁴

Federal Power

The U.S. Government is the second largest producer of electricity in the United States (Table 1). Ultimate consumers of Federal generation paid on average only 3.47 cents per kWh in 1984, the lowest rate among the ownership types (Table 2). Federal power is not generated for profit. The goal of all Federal power producers is to provide power at the lowest possible rate consistent with sound business principles, giving preference to public bodies and cooperatives in the sale of electricity.

The Federal Government is primarily a generator and wholesaler of electricity, rather than a distributor to ultimate consumers. In 1984, it sold only 25 percent of its generation directly to ultimate consumers (Table 1). Most Federal generation is wholesaled to municipal electric utilities, cooperatives, and other nonprofit preference customers, as required by law.

²This chapter presents 1984 rather than 1985 data because sufficient 1985 data are not yet available.

³Energy Information Administration, *Financial Statistics of Selected Electric Utilities 1984*, DOE/EIA-0437(84) (Washington, DC, February 1986), p. 8.

⁴Securities and Exchange Commission, *Fifty-First Annual Report 1985* (Washington, DC, 1985), p. 138.

Table 1. Selected U.S. Electric Utility Statistics, 1984

Type of Utility	Number in each Group	Number of customers		Sales		Operating Revenue		Installed Nameplate Capacity		Generation	
		(millions)	%	(billion kWh)	%	(billion dollars)	%	(gigawatts)	%	(billion kWh)	%
Investor-Owned*	236	74.3	76.1	1,739.5	76.3	128.3	73.7	514.9	76.6	1,848.9	76.5
Cooperatives	938	9.8	10.1	155.4	6.8	17.7	10.2	24.7	3.7	102.0	4.2
Municipals	1,811	11.6	11.9	264.8	11.6	15.3	8.8	36.7	5.5	74.7	3.1
Federal	10	*	—	62.5	2.7	7.9	4.5	63.3	9.4	253.9	10.5
Other Public Entities*	135	1.9	1.9	56.2	2.5	4.8	2.7	32.8	4.9	136.8	5.7
Totals	3,130	97.6	100.0	2,278.4	100.0	174.0	100.0	672.5	100.0	2,416.3	100.0

* Fewer than 50,000 customers.

* Data include 178 largest utilities only; these utilities are believed to provide more than 90 percent of operating revenue for investor-owned utilities.

* Other public entities include public power districts, State authorities, irrigation districts, and State organizations.

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

Sources: Installed capacity and generation data: Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry* (1984). Number, sales, and revenue data: *Investor-owned utilities: Energy Information Administration, *Financial Statistics of Selected Electric Utilities 1984* (February 1986); *Cooperatives, municipals and other public entities: Compiled by the Data Analysis and Forecasting Branch, Electric Power Division, Energy Information Administration from sources listed in Appendix D.

Federal electricity generation reaches consumers in 34 States. Two Federal agencies are the primary producers of Federal hydroelectric generation: the U.S. Army Corps of Engineers of the Department of Defense and the Department of the Interior's Bureau of Reclamation. The Corps operates throughout the country; the Bureau of Reclamation operates in the Western States. All electricity generated by them is marketed by four Federal power marketing administrations: Bonneville, Southeastern, Southwestern, and Western Area. The power marketing administrations, part of the Department of Energy, generally operate in all States but those in the Northeast, upper Midwest, and Hawaii. Four of the five power marketing administrations own transmission lines; only the Southeastern Power Administration owns none. In addition to these major Federal power organizations, the Alaska Power Administration operates its own dams and distributes power from them, and the Bureau of Indian Affairs operates dams and sells power to ultimate consumers. Also, the Department of Defense operates power plants for several of its installations scattered throughout the Nation. The Tennessee Valley Authority (TVA), the largest Federal power producer, is not part of a Federal department, but is instead a Government corporation.

While investor-owned utilities must compete for private capital, Federal power producers must compete for funds in the Federal budget process. The power marketing administrations are obligated to repay the capital costs plus operation and maintenance costs within 50 years. The TVA is also authorized to issue securities.

Municipal Utilities

Municipally owned electric utilities generate the least electricity but comprise the single most numerous ownership group. Municipals have the second largest share of customers and sales of the five ownership groups. In 1984, 72 percent of municipals' sales were made up by purchases of Federal, private, and other public power. Average revenue per kWh sold in 1984 was 5.69 cents (Table 2), about 1 cent per kWh less than power from private utilities. This difference is the result of exemption from local, State, and Federal taxes, access to less expensive capital via public financing, access to less expensive Federal power, and no requirement to pay dividends.

Table 2. U.S. Electric Utility Revenue From Sales to Ultimate Consumers, 1984

Type of Utility	Billion Dollars	Percent	Cents per Kilowatthour*
Investor-Owned	113.0	79.0	6.50
Cooperatives	10.4	7.3	6.70
Municipals	15.1	10.5	5.69
Federal	2.2	1.5	3.47
Other Public Entities	2.5	1.7	4.37
Total	143.1	100.0	6.28 (average)

* Derived from revenue data in this table and energy sales data in Table 2.

Sources: *Data for investor-owned utilities: Energy Information Administration, *Financial Statistics of Selected Electric Utilities 1984* (February 1986); *Other data: Compiled by the Data Analysis and Forecasting Branch, Electric Power Division, Energy Information Administration from sources listed in Appendix D.

Municipal electric utilities are nonprofit local government agencies established to serve their communities and nearby customers at the lowest possible cost. Most municipal utilities simply distribute power, although some larger ones generate, transmit, and distribute it. They are controlled either by a governing body such as a city council, or by an independent utility board. Municipal electric utilities obtain their financing from municipal treasuries and from revenue bonds secured by proceeds from the sales of electricity. Municipal utilities operate in all States except Hawaii (Figure 1). Three-fourths of municipal utilities operate in communities with populations of 10,000 or fewer persons. Most municipal sales occur in the Southeast and on the Pacific Coast, primarily because inexpensive Federal hydroelectric power is available in these areas.

Cooperatives

Rural electric cooperatives, currently operating in 46 States, rank third in number of customers and sales, and second in operating revenue, but have the least installed capacity among the ownership categories (Table 1). The difference between cooperatives' sales and generation is made up by purchases from private companies, the Federal Government, and other public agencies. In 1984, cooperatives' average revenue from

sales to ultimate consumers was 6.7 cents per kWh, the highest of any of the five ownership types (Table 2), resulting from large construction programs in the 1970's.

Cooperatives are owned by and provide electricity to their members. The Rural Electrification Administration, the National Rural Utilities Cooperative Finance Corporation, the Federal Financing Bank, and the Bank for Cooperatives are the most important sources of cooperatives' debt financing.

Other Public Entities

Other public entities include public power districts, State authorities, irrigation districts, and other State organizations. Public power districts and projects are concentrated in Nebraska (which has no private electric utilities), Washington, Oregon, Arizona, and California. In 1984, other public entities generated much more power than they sold to end-users. The difference between generation and direct sales was in sales to municipalities and cooperatives. Ultimate consumers paid 4.37 cents per kWh in 1984 for electricity from these entities, the second lowest of any of the ownership types (Table 2). Relatively low costs result from generation with inexpensive hydroelectric power, ac-

Figure 1. Location of Municipal and Other Public Utilities

Source: American Public Power Association, *The Public Benefits of Public Power*, May 1984, pp. 6-7.

cess to Federal power, access to relatively inexpensive capital, and no requirement to pay dividends. The capital structure of the power districts and projects is much

like that of the municipal utilities; financing is obtained from the public entities' treasuries or from revenue bonds secured by proceeds of electricity sales.

2. Electric Utility Regulation

The basic purpose of public utility regulation is to assure adequate service to all public utility patrons, without discrimination and at the lowest reasonable rates consistent with the interests both of the public and the electric utilities. The rationale for public utility regulation rests upon two propositions: (1) the important role that utilities serve in a modern society, and (2) their existence as local monopolies.

Traditionally, industries that serve a broad public purpose in an important way are subject to public control. This view is derived from English common law. Historically, economies of scale in electricity generation and distribution served to reinforce the notion that utilities serve the public best as regulated entities.

Determination of Regulatory Jurisdiction

U.S. electricity generating facilities are owned (a) by an individual utility; (b) jointly with utilities of the same ownership type; or (c) jointly with utilities of different ownership types. Investor-owned utilities (IOU's) own facilities either individually or in "joint venture" arrangements with other investor-owned utilities, State/municipal systems, and rural electric cooperatives. Similarly, State/municipal systems and rural electric cooperatives individually own production facilities and participate in various joint ownership arrangements among themselves and with investor-owned utilities. No Federal production facilities are jointly owned with other ownership types. Joint action agencies are a relatively recent phenomenon for publicly owned municipal systems; they allow two or more municipal utilities and/or other power systems to finance and construct generation and transmission facilities.⁵

Electric utility activities are related to the facilities they own. Because regulators are responsible for different types of activities, the distribution and types of facilities determine who has responsibility for the various utility operations. The wholesale system sales in

Figure 2 show three types of electricity flows: (1) wholesale (or resale) sales between different ownership types; (2) wholesale (or resale) sales between different utilities of the same ownership type; and (3) the flow of electricity through an individual utility's vertically integrated electric system. The figure underscores the diversity of the U.S. electric utility system. Besides integrated system sales and sales between utilities of the same ownership type, utilities of each ownership type sell, to varying degrees, electricity at wholesale to utilities of each of the other ownership types. This distribution and the final sale of electricity to ultimate end-users is accomplished by each of the ownership types.⁶

Who Regulates Public Utilities

Regulation of the electric utility system is accomplished by different regulatory bodies, including Federal and State regulators. Generally, intrastate utility services are subject to State regulation. Those which cross State lines (interstate) become subject to a State commission for some of their activities, while at the same time being subject to a Federal commission for activities of an interstate character.

Federal Regulators

Federal Energy Regulatory Commission

The Federal Energy Regulatory Commission (FERC) was established by Congress on October 1, 1977, as an independent agency to oversee certain aspects of the natural gas, electric utility, hydroelectric, and oil pipeline industries. Under the Department of Energy Organization Act (P.L. 95-91), FERC succeeded the Federal Power Commission, which was established by the Federal Water Power Act of 1920 (P.L. 66-280) to license hydroelectric projects owned by private companies and State and local governments. The Federal

⁵Oak Ridge National Laboratory, *Regulation, Pricing, and Comparative Performance in the U.S. Electric Utility Industry by Ownership Type* (Oak Ridge, Tennessee, September 1984), pp. 3.1 and 3.3.

⁶Oak Ridge National Laboratory, *Regulation, Pricing, and Comparative Performance*, p. 3.3.

Figure 2. Schematic Representation of the U.S. Electric System by Ownership Type

Source: Oak Ridge National Laboratory, *Regulation, Pricing, and Comparative Performance in the U.S. Electric Utility Industry*, March 1984.

Power Act of 1935 (Title II of the Public Utility Holding Company Act of 1935, P.L. 74-333) provided for regulation of investor-owned electric utility wholesale rates and transactions.

FERC is composed of five members, one of whom is designated Chairman, nominated by the President and approved by the Senate. A major function with respect to electric utilities is to approve rates and standards for IOU's wholesale electricity sales in interstate commerce. These transactions--between IOU's or between IOU's and municipalities or cooperatives--comprise about 15 percent of U.S. total electric sales.⁷

FERC determines whether wholesale electricity rates are just and reasonable and not unduly discriminatory. Agreements for interconnection between utility systems and the wheeling (use of the transmission facilities of one electric system to transmit the power of, and for, another system) of electricity among utilities are filed with FERC. In addition, FERC oversees utility mergers, issuance of certain stock and debt securities, and interlocking relationships among top officials in utilities and major firms doing business with utilities. FERC also approves the rates of Federal Power Mar-

keting Administrations. The Public Utility Regulatory Policies Act of 1978 (P.L. 95-617) further broadened the scope of FERC's authority to encompass the ordering of interconnections and wheeling among utilities, and the administration of the statutory benefits for qualifying small power producers and cogeneration facilities provided by the Act.

FERC issues preliminary permits, licenses, and exemptions from licenses to build and operate non-Federal hydroelectric projects, and is responsible for the safe operation of approximately 1,500 licensed dams. Projects under FERC jurisdiction include non-Federally owned hydroelectric facilities installed at Federal projects, for example, a powerhouse installed at a U.S. Army Corps of Engineers dam used for flood control or navigation. FERC seeks to preserve environmental quality and ensure public safety at hydroelectric sites by including protective measures in its licensing orders. Licenses issued by FERC contain conditions for protection of fish and wildlife, water quality, historical and archaeological sites, scenic and cultural values, and provision for recreational opportunities, flood control, and dam safety.⁸

⁷Federal Energy Regulatory Commission, *1984 Annual Report* (Washington, DC, March 1985), p. 2.

⁸Federal Energy Regulatory Commission, *1984 Annual Report*, p. 2.

Regulatory Commissions often hold hearings on electric utility licensing, ratemaking, and other issues.

Economic Regulatory Administration

The Economic Regulatory Administration (ERA) was created by the Department of Energy (DOE) Organization Act of 1977 (P.L. 95-91). The ERA is headed by an Administrator who reports to the Secretary of Energy, and is nominated by the President and confirmed by the Senate. The most important responsibility assigned to ERA under the Department of Energy organization was the authority to regulate the price of petroleum products, formerly carried out by the Federal Energy Administration, a predecessor of DOE. The remaining petroleum price controls were lifted by Executive Order in January 1981. ERA administers other regulatory programs, including a program to convert oil- and gas-fired electric utility and industrial facilities to burn coal pursuant to the Powerplant and Industrial Fuel Use Act (FUA, P.L. 95-620), authority to issue exemptions from oil and natural gas under FUA, and the regulation of international electricity transmission connections and licensing of exports of power.

A utility that wishes to construct international electricity transmission lines must obtain a Presidential Permit for the lines to cross U.S. borders. Once the transmission lines have crossed international borders, the utility must have an authorization to export power. No authorization is required to import power.

Environmental Protection Agency

The Environmental Protection Agency (EPA) was established on December 2, 1970. EPA is an independent agency in the Executive Branch headed by an Administrator who is nominated by the President and confirmed by the Senate. Reducing air pollution from fossil-fueled steam-electric plants is one of the major responsibilities of EPA. Of primary concern is the reduction in the emission levels of sulfur and nitrogen oxides. These oxides are present in stack gases from coal, oil, and gas furnaces and in the exhaust gases from internal combustion engines and gas turbines. They can be harmful to humans, animals, and plants. EPA has established emission standards for stationary and mobile sources.

Among its regulatory responsibilities, EPA:

- Establishes national air quality standards for all air pollutants
- Sets limits on the level of air pollutants emitted from such stationary sources as power plants, municipal incinerators, factories, and chemical plants

- Develops guidelines to control discharges of specific water pollutants, including radiation.⁹

While standard-setting and supervisory powers are now vested in the EPA, the States retain primary responsibility for implementing and enforcing standards.

Nuclear Regulatory Commission

The Nuclear Regulatory Commission (NRC) was created by the Energy Reorganization Act of 1974 (P.L. 93-438) and began operation in January 1975. It assumed the nuclear regulatory and licensing functions of the Atomic Energy Commission (AEC), which was abolished. The other functions of the AEC, primarily nuclear research and development, were taken over by the Energy Research and Development Administration (which later became part of the Department of Energy).

NRC is composed of five Commissioners nominated by the President and confirmed by the Senate. Commissioners serve 5-year terms with one Commissioner appointed by the President to serve as Chairman. Specifically, the NRC:

- Licenses the construction and operation of nuclear reactors and other nuclear facilities
- Licenses the possession, use, transportation, handling, and disposal of nuclear materials
- Regulates licensed activities for the physical protection of nuclear facilities and materials
- Develops and implements rules and regulations governing licensed nuclear activities
- Conducts public hearings on radiological safety, environmental, common defense, security, and antitrust matters
- Develops effective working relationships with States regarding the regulation of nuclear materials
- Licenses the export of nuclear reactors and the export and import of uranium and plutonium.¹⁰

Securities and Exchange Commission

The Securities and Exchange Commission (SEC) is an independent regulatory agency established in 1933 to regulate interstate transactions in corporate securities and stock exchanges. Its five members are nominated by the President and confirmed by the Senate for 5-year terms. The President also designates one of the members to serve as Chairman.

The SEC oversees the disclosure of accurate information to the public about public offerings of securities and periodic financial statements of public companies. In addition, security exchangers, brokers, and dealers with interstate activities must register with the SEC and comply with SEC standards in the conduct of their business. Under the Public Utility Holding Company Act of 1935, the SEC regulates the purchase and sale of securities, utility properties, and other assets by registered public utility holding companies and their electric and gas subsidiaries.

State Regulation

The goal of public utility regulation at the State level is to provide adequate nondiscriminatory service to electricity consumers at just and reasonable prices. State legislatures have granted public utility commissions the power to accomplish this goal.

The role of the Public Utility Commission is to ensure that regulated firms operate efficiently and to promote the public interest. Regulators restrain the exercise of monopoly power by approval of electricity price levels and rates of return for the stockholders of the utility. State regulators also approve the franchise under which the utility operates. End-use sales by investor-owned utilities are regulated by individual commissions in the States in which the utility distributes electricity (Table 3). The one exception is the State of Nebraska, where all electricity sales are made by publicly owned utilities.¹¹ Retail sales of electricity by State/municipal systems are generally under the jurisdiction of either the local governing board or an independent electricity board elected or appointed to oversee the operation of the publicly owned system.

Regulatory techniques of State Commissions extend far beyond the setting of limits of rates of return. Licensing and site certification are also important functions of some State Commissions. The regulatory requirements that must be satisfied in order to build a new plant are widely diversified among the States. In some States, a regulatory agency's involvement in a power plant project may begin with an assessment of the need for a plant, followed by reviews of the utility's study to select an appropriate site. In other States, no government approval is needed until the utility is ready to operate the facility. The types of State agencies that have authority in the site selection process may include a Public Utility Commission, State Environmental Protection Agency, Energy Resources Management Administration, or Power Plant Siting Board.¹² These agencies have differing charters and their involvement

⁹Congressional Quarterly, *Federal Regulatory Directory 1981-1982* (Washington, DC, 1981), p. 113.

¹⁰Congressional Quarterly, *Federal Regulatory Directory 1981-1982*, p. 489.

¹¹Oak Ridge National Laboratory, *Regulation, Pricing, and Comparative Performance*, pp. 3.4-3.5.

¹²United Engineers and Constructors, Inc., *Analysis of Preconstruction, Engineering and Construction Schedules--400 MW Coal-Fired Power Generating Facility* (1984), p. 2.

Table 3. Number of State Commissioners and Electric Utilities Under Regulatory Jurisdiction, 1984

State	Agency	Number of Commissioners			Number of Utilities Under Agency Jurisdiction		
		Total	Elected	Appointed	Private	Public	Cooperative
Alabama	PSC	3	X		1	0	0
Alaska	PUC	5		X	27	15	15
Arizona	CC	3	X		6	0	11
Arkansas	PSC	3		X	4	3	19
California	PUC	5		X	8	0	4
Colorado	PUC	3		X	3	13	30
Connecticut	DPUC	5		X	3	0	0
Delaware	PSC	5		X	2	0	1
DC	PSC	3		X	1	0	0
Florida	PSC	5		X	6	34	16
Georgia	PSC	5	X		2	0	43
Hawaii	PUC	3		X	5	0	0
Idaho	PUC	3		X	5	0	0
Illinois	CC	7		X	13	0	0
Indiana	PSC	5		X	9	71	46
Iowa	SCC	3		X	9	139	60
Kansas	SCC	3		X	7	15	37
Kentucky	PSC	3		X	8	0	24
Louisiana	PSC	5	X		5	0	4
Maine	PUC	3		X	6	6	5
Maryland	PSC	5		X	5	5	4
Massachusetts	DPU	3		X	8	40	0
Michigan	PSC	3		X	12	0	14
Minnesota	PUC	5		X	7	128	54
Mississippi	PSC	3	X		2	21	28
Missouri	PSC	5		X	8	0	0
Montana	PSC	5	X		6	0	0
Nebraska	PSC	5	X		0	0	0
Nevada	PSC	5		X	3	0	11
New Hampshire	PUC	3		X	5	3	1
New Jersey	BPU	3		X	4	9	1
New Mexico	PSC	3		X	6	0	21
New York	PSC	7		X	11	0	5
N. Carolina	UC	7		X	6	0	0
North Dakota	PSC	3	X		3	0	0
Ohio	PUC	5		X	9	0	0
Oklahoma	CC	3	X		4	0	31
Oregon	PUC	1		X	4	15	18
Pennsylvania	PUC	5		X	13	4	0
Rhode Island	PUC	3		X	4	1	0
S. Carolina	PSC	7		X	6	0	0
South Dakota	PUC	3	X		6	0	0
Tennessee	PSC	3	X		4	0	22
Texas	PUC	3		X	10	69	86
Utah	PSC	3		X	2	0	10
Vermont	PSB	3		X	10	15	2
Virginia	SCC	3		X	6	0	13
Washington	UTC	3		X	3	0	0
West Virginia	PSC	3		X	15	2	2
Wisconsin	PSC	3		X	13	84	0
Wyoming	PSC	3		X	6	8	19

PSC: Public Service Commission.

PUC: Public Utilities Commission.

CC: Corporation Commission.

DPUC: Department of Public Utility Control.

SCC: State Corporation Commission.

DPU: Department of Public Utilities.

BPU: Board of Public Utilities.

UC: Utilities Commission.

PSB: Public Service Board.

UTC: Utilities and Transportation Commission.

Source: National Association of Regulatory Utility Commissioners, 1984 Annual Report on Utility and Carrier Regulation (November 1985), pp.

417, 847-869.

with the applicant varies from a cursory to a highly detailed review.

A wide variety of actions, such as mergers, purchases and sales of property, and issuance of securities, requires commission approval. Other areas into which some commissions have entered in order to ensure that

utility activities are in keeping with the public interest include setting rules about when competitive bids are required, promulgating company performance standards, deriving methods for allocating power during shortages, establishing billing rules, safety, preventing damage to underground facilities, and promoting conservation.

How Electric Utilities are Regulated

The major ongoing activity of State regulatory commissions is to determine how electricity should be priced. In general, State commissions have sought to set electricity prices by trying to see that the quantity and price of electric service from the regulated utility come as close as possible to the amounts that a competitive market would produce. The most common method is to tie utility revenue and prices to the "cost of service" and to require that all customers have nondiscriminatory access to electric service at a price that covers the cost of producing the service. This price is equal to the long-run price of a commodity in a competitive market. The cost of service should include a fair market return to all the resources used in the production of electricity, including capital.

Cost-of-Service Regulation

Cost-of-service regulation is implemented by establishing the revenue requirements of the utility in regulatory proceedings. Revenue requirements are set to reimburse the utility for providing electricity. In order to determine the revenue requirements, commissions generally use rate-base regulation applied to standardized utility accounts. The accounting principles to be followed by regulated utilities are defined and ordered by the commissions and are used to allocate costs for rate-making purposes. The process of determining electricity prices generally follows three stages: (1) revenue requirements are determined; (2) the revenues are allocated to different classes of service; and (3) rate structures for each class of service are determined.

Revenue Requirements

The basic process of determining revenue requirements in commission proceedings usually takes place in formal hearings. The objective is to assign values to the elements in the formula:

$$R = E + r(V - d)$$

where

R = Revenues

E = Operating expenses

V = Value of the rate base

r = Rate of return

d = Accumulated depreciation

R is revenues that the commission determines will provide the utility with an adequate return for the cost of providing electric services. It is the sum of operating expenses (E) and the return to capital employed (r) times the current amount of capital in use ($V - d$).

The revenue requirement is, in a sense, the forecast (or test-year) cost of providing services for some period, usually a year, in the future. Expenses include outlays for fuel, wages, taxes, and depreciation for the period in which the revenues are to be earned. The rate of return to capital is the proportionate payment for the use of funds tied up in physical plant and working capital. The rate base is the value of the stock of capital (plant and equipment) used to produce electricity and to run the utility; accumulated depreciation, representing capital already used, is subtracted from the rate base to determine its current value.

The Public Utility Commission reviews all the items in a utility's rate filing to determine that the charges are fair and reasonable. Since the approved revenues represent future costs and earnings, allowances for anticipated changes in circumstances, such as wage increases, may also be taken into account. Individual expense items, such as advertising outlays, legal fees for regulatory proceedings, or contributions to industry groups, may be challenged. In each case, the commission determines if the allowed expenses are fair and reasonable and contribute to the utility's service to the public. During the 1970's, unsettled conditions in fuel markets increased the difficulty of knowing future fuel costs and led many commissions to introduce automatic fuel-adjustment clauses to revenue determination. These adjustments allow utilities to bill customers automatically for all or part of unanticipated incremental changes in fuel costs as they occur. Otherwise, expenses approved by the commission determine the costs a utility is allowed to recover from customers.

The calculation of the rate of return times the undepreciated balance of the rate base, $r(V - d)$ in the formula, determines the net income of the utility. This is the allowed earnings on capital, and it must cover the utility's interest payments and the income to the owners of the utility. The latter is used to pay dividends to the stockholders and to make additions to retained earnings. The rate base consists of the undepreciated balance of the original cost of capital stock employed by the utility that is "used and useful." This cost must have been incurred in a reasonable and prudent fashion in order for the commission to allow the cost to enter the rate base. The used and useful rule means that capital equipment that is not in use cannot be charged to the ratepayers.

Commissions may judge that utility investments have not resulted in additional used and useful capital. A commission may determine that a new plant is not needed in order for the utility to provide service. In such a case, the commission may disallow some or all of the expenses associated with the facility and exclude all or part of the capital from the rate base. In an

extreme case, a commission could find that a utility has been imprudent or has not exercised due diligence in the expenditure of funds and deny the utility the right to recover such funds from ratepayers at any time in the future. The owners of the company are at risk for the funds. In recent years, this used and useful standard, in combination with the requirement that undertakings be managed in a reasonable and prudent manner, has created a quandary for utilities and commissions alike. For example, if a utility starts building a nuclear-powered generating plant based on a forecast of demand growth rate of 7 percent a year, then later finds that demand expansion has slowed, the plant may not be used and useful if completed as scheduled. On the other hand if the plant were to be canceled at this stage, it is possible that the expenditures to date could be held imprudent by a commission. A commission has the responsibility to see that adequate provision is made to supply electricity, and that the price at which electricity is supplied is as low as is consistent with good management.

The final element of revenue requirement is the allowed rate of return on the rate base (r in the formula). This is frequently the element about which there is the most controversy and uncertainty. The difficulty arises because determining the fair return to capital supplied by the owners of the utility rests upon subjective judgment. The return on the debt share of financing is set by the cost of borrowing funds (short-term bank loans and longer-term bonds). The capital supplied by preferred equity also has a predetermined cost, set when the stock is issued. However, capital raised through common stock sales bears no fixed rate of return. The overall rate of return allowed by the commission must be sufficient to pay fixed debt obligations and to yield a return to stockholders just large enough to permit the utility to have continued access to capital markets. The allowed rate of return is the utility's weighted cost of capital. But since the utility's obligation to make debt-interest payments and pay preferred dividends is contractual, only the return to common stockholders is affected by changes in the allowed rate of return.

Allocating Revenue Requirements

Once a commission has determined a utility's revenue requirements, the distribution of the sources of revenues must be established. Again the cost of service to particular classes of customers and the mix of customer classes served provide guidelines to the determination of how much of the revenues must be collected from each customer class. In general, customers are divided into classes by the type of service they receive. The primary classifications are residential, commercial, industrial, and other. However, there may be subsets within each class. For example, residential customers

may be put in groups (such as all-electric homes, general service plus water heating, or general service only), each with distinct revenue streams determined by the cost of providing distinct types of service. Furthermore, a utility's service territory may be divided into regions reflecting different costs of service to different places. The number and types of customer classes are defined so as to group together customers with similar usage patterns that affect the cost of supplying service to each class. The number of classes is limited by administrative costs and the number of known characteristics by which customers can be grouped; thus most utilities will have only a few subsets of customer types within each of the major classes.¹³

Setting Tariffs

After the revenue requirements are distributed, rates or tariff schedules for service for each class are designed. These rate schedules are the basis for customer billing; they describe the prices customers will be charged for services. Tariffs for electric service can take a number of forms. The simplest form may be a flat rate per kilowatthour for each metered kilowatthour consumed. The customer is billed for the price times quantity consumed, plus fuel adjustment charge times quantity, and taxes. However, many more complex tariff structures are also used. These include: fixed-demand charges plus an energy charge per unit of consumption; fixed-demand charges plus block rates that change depending on quantity of electricity consumed; a fixed price for all services; or rates that change with the time of day or season of the year. Each tariff schedule is intended to generate revenues to the utility that cover the full cost of all services to the customer for which it applies and, in aggregate, to equal the total revenue requirement.

Exceptions to full cost-recovery may be approved by the commissions in special cases, for example, to provide subsidized rates to low-income residential customers. In these cases, some provision must be made to make up the revenue losses. The revenues could be made up by increasing charges to other customer classes or by grants from some governmental or private entity. Commissions sometimes also approve subsidized rates for customer classes other than low-income residential customers when the benefits of special electricity rates to the entire community appear to outweigh the costs of the subsidy to other customers.

The total receipts from electricity sales eventually realized by a utility may not equal the revenue requirements approved by the commission. If realized revenues are too low, the utility will ask for permission to modify tariff schedules. If realized revenues exceed required amounts, the public may petition the commis-

¹³Paul J. Garfield and Wallace F. Lovejoy, *Public Utility Economics* (Englewood Cliffs, New Jersey: Prentice Hall, 1964), pp. 134-164.

sion to order reductions in tariffs. In fact, the ability to match revenue requirements to allocated cost of service and their derivative tariff schedules has provid-

ed one of the major strengths of rate-base regulation procedures.

3. Outlook for U.S. Electric Power, 1985-1995

The outlook for the U.S. electric utility industry depends upon several factors, including the overall rate of economic growth, the price and availability of fuels, the price of electricity relative to other energy prices, and the type and rate of growth of new generating capacity. This chapter presents a range of projections for electricity supply, demand, and prices for the years 1985 through 1995.¹⁴ Because actual conditions will almost certainly differ from any set of assumptions, the various scenarios are provided here as much to illustrate the likely role, direction, and magnitude of effects of important factors that affect the market as to provide the overall projections.

This report focuses and expands upon the U.S. energy projections described in the *Annual Energy Outlook 1985* (AEO). Five projection scenarios are covered in this chapter: (1) a base case, (2) a lower-than-base economic growth case, (3) a higher-than-base economic growth case, (4) a high electricity demand case, and (5) a reduced capacity growth case (Table 4). World oil prices are assumed to be higher than in the base case for the low economic growth scenario; they are assumed to be lower than in the base case for the high economic growth and high electricity demand cases. Despite recent sharp drops in world oil prices, this report is based upon the longer term assumption that the real prices of crude oil are likely to come down and stay low the next few years, but then recover and resume an upward trend by the end of the decade.

National and regional projections are given in this *Annual Outlook for U.S. Electric Power* (Outlook). Regional estimates for the base and alternate cases are presented in Appendix A, Tables A2-A11. The regional projections, however, are more uncertain than the national projections, because of the lack of regional data needed to determine the forecasts.

Base Case

Demand

In the base case, U.S. electricity demand (end-use consumption) is expected to grow at a rate slightly less than the overall rate of economic growth, but much more rapidly than other categories of energy end use. The average rate of growth of electricity demand is projected to be 2.7 percent a year, close to the Gross National Product (GNP) growth rate of 2.8 percent a year.

The shares of electricity consumption among the three major end-use sectors--residential, commercial, and industrial--are expected to remain essentially constant over the period from 1985 through 1995. Historically, the industrial sector has been the largest end user of

Table 4. Projected Growth Rates for Gross National Product, World Oil Prices, and Electricity Demand, 1985-1995 (Percent)

Case	Gross National Product	World Oil Price	Electricity Demand
Low	2.4	3.2	2.5
Base	2.8	1.1	2.7
High	3.2	-0.4	2.9
High Electricity Demand	3.6	-0.4	3.2
Reduced Capacity	2.8	1.1	2.7

Sources: ●Low, base, and high cases: Energy Information Administration, *Annual Energy Outlook 1985* (February 1986). ●High demand and reduced capacity cases: Energy Information Administration, Intermediate Future Forecasting System (IFFS), IFGMLX.D1127851 and IFGMMM.D1118852.

¹⁴1985 values are estimates; actual values, not available during preparation of this analysis, can be obtained from the Energy Information Administration, *Annual Energy Review 1985*, DOE/EIA-0384(85) (Washington, DC, May 1986).

electricity; its share of electricity use is projected to remain about 37 percent. The share of the second largest sector, residential, is expected to be approximately 34 percent, and that of commercial, about 29 percent (Table 5).

Electricity demand from 1985 through 1995 is now projected to grow more slowly than predicted last year; furthermore, expectations for 1985 through 1995 now fall below actually experienced growth rates from 1970 through 1984. Last year's Outlook projected an average electricity demand growth rate of 3.2 percent

Table 5. Projections for U.S. Electric Power, 1985-1995, Selected Values, Various Growth Cases

Growth Case	Middle (Base)			1995			
	1985 ^a	1990	1995	Low Growth	High Growth	High Demand	Reduced Capacity
Electricity Demand (billion kilowatthours)							
Residential	780	905	1,023	1,011	1,040	1,057	1,024
Commercial/Other	673	789	891	878	904	917	893
Industrial	864	957	1,113	1,076	1,150	1,199	1,118
Total End-Use Consumption	2,317	2,651	3,026	2,964	3,093	3,173	3,035
Net Capability^b (million kilowatts)							
Coal Steam	280	295	319	319	319	319	300
Other Fossil Steam ^c	145	141	135	135	135	135	135
Combined Cycle	5	5	5	5	5	5	5
Combustion Turbine	43	45	61	57	69	84	74
Nuclear Power	79	105	111	111	111	111	105
Hydroelectric/Other ^d	74	76	77	77	77	77	77
Pumped Storage							
Hydroelectric	16	18	19	19	19	19	19
Total Capability	642	685	727	722	735	750	715
Capability Additions, Cumulative 1985-95 (million kilowatts)							
Planned by Utilities	--	--	99	99	99	99	74
Additional EIA Estimates	--	--	17	13	25	40	30
Total Additions	--	--	116	112	124	139	104
Generation by Fuel Type (billion kilowatthours)							
Coal	1,399	1,569	1,790	1,769	1,809	1,833	1,717
Natural Gas	293	285	340	322	294	315	366
Oil	99	101	161	134	259	302	241
Nuclear	383	562	606	606	606	606	582
All Hydroelectric/Other ^e	284	322	328	328	328	328	327
Total Generation	2,457	2,838	3,225	3,159	3,296	3,383	3,233
Price (1985 mills per kilowatthour)^f							
Capital ^g	28.1	27.5	20.9	20.5	21.0	21.1	19.5
Fuel ^h	21.8	21.3	24.1	23.9	24.3	25.4	25.9
Operation and Maintenance ⁱ	16.3	16.4	15.7	16.0	15.7	15.6	15.3
Total Price	66.2	65.2	60.7	60.4	60.9	62.2	60.8

^a 1985 is considered a forecast year in this Outlook. Since its preparation, actual 1985 data for many variables have become available and are published in the Energy Information Administration, *Annual Energy Review 1985* (May 1986).

^b Net Capability (Net Summer Capability): 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.

^c Other includes oil, gas, and dual-fired capacity.

^d This category includes pondage hydropower and renewable sources such as thermal power, wood, waste, solar energy, and wind.

^e This category includes conventional and pumped storage hydroelectric power and other renewable sources such as geothermal power, wood, waste, solar energy, and wind.

^f Prices are model simulations and represent average revenues per kilowatthour of demand over all customer classes.

^g The capital component represents the cost to the utility of capital assets needed to provide reliable service. It includes plant depreciation, taxes, and a sufficient return on invested capital to cover interest obligations on outstanding debt and to compensate stockholders.

^h The fuel component includes only the direct costs of fuel inputs used to generate electricity required to meet demand.

ⁱ The operation and maintenance (O&M) component includes all nonfuel costs necessary to operate and maintain generation, transmission, and distribution capacity used to deliver electricity to end-use sectors.

Note: Totals may not equal sum of parts because of independent rounding.

Sources: ^aLow, middle (base), and high cases: Energy Information Administration, *Annual Energy Outlook 1985* (February 1986). ^bHigh demand and low capacity cases: Energy Information Administration, Intermediate Future Forecasting System (IFFS), IFGMLX.D1127851 and IFGMMM.D1118852.

a year from 1985 through 1995. To put these projections in perspective, end-use electricity consumption grew at an average annual rate of 3.6 percent from 1970 through 1984 (Appendix C). This Outlook also projects an electricity demand growth rate at no more than the overall economic rate of growth. Historically, based on 10-year periods, electricity demand has grown more rapidly than GNP (Table 6); last year's Outlook projected an electricity demand growth rate almost 20 percent greater than that for GNP from 1985 through 1995.¹⁵

The projected slowdown in electricity demand growth is traced primarily to reduced expectations for industrial electricity demand growth. Growth in the major energy-intensive industries, such as primary metals, chemicals, and stone, clay, and glass, is projected to be below GNP growth because these industries have not fully recovered from the sharp drops of the last recession and also face increased competition from imports. The EIA also assumes that industrial conservation and efficiency improvements made as a result of the rapid energy price increases of the 1970's will continue and expand, reducing the rate of growth of industrial electricity demand. As a result, U.S. industrial electricity demand is now projected to grow less rapidly than GNP, at less than 2.6 percent a year (Table 5). Rather than increasing its share of total U.S. electricity consumption in the future, as expected in last year's forecast, industrial electricity use is now projected to maintain its current share.

Although electricity end-use consumption is not expected to grow as rapidly as GNP, it is projected to grow more rapidly than other energy use or total end-use energy consumption (Tables ES1 and 7). As a result, electricity is expected to comprise a much larger share of each sector's total energy end use (except transportation) by 1995. Growth in electricity consumption accounts for more than 70 percent of all

projected growth in residential energy end use from 1985 through 1995; as a consequence, the share of residential energy end use attributed to electricity is expected to rise to almost 35 percent in 1995, up from 30 percent in 1985. Electricity, which was 39 percent of all commercial energy end use in 1985, is projected to rise to 45 percent in 1995, accounting for more than 90 percent of all energy growth in that sector. In the industrial sector, electricity is projected to capture 60 percent of energy end-use consumption growth, increasing from 14 percent of industrial energy end use in 1985 to almost 17 percent in 1995.

Furthermore, electricity growth contributes much more to growth in total U.S. energy use over the period from 1985 through 1995 than is described by end-use consumption measures alone. Electricity generation involves large energy conversion losses, expending an average of about 3 units of input energy for every 1 unit of output electricity. Total U.S. (primary) energy use in 1995 is projected to be about 9.5 quadrillion Btu greater than in 1985. More than 85 percent of this increase, about 8.3 quadrillion Btu, is attributed to projected growth in electric utility energy use (Table 7).

Despite large conversion losses and a higher unit price, electricity is increasingly chosen over alternate energy sources. In contrast to other fuels, electricity's price is projected to decline over the forecast period. In general, moreover, while more costly as an individual unit of energy, electricity is often more efficiently delivered to the point of use than other energy forms and often comprises only a small part of the total cost of a demanded service. For example, the cost advantages of electricity over other fuels is apparent in meeting many lighting needs, in powering motors, and in communications and computer applications.

Table 6. Historical and Projected Ratios, Average Annual Rates of Growth of U.S. Net Electricity Generation to Real Gross National Product, 1900-1990

Initial Year	Final Year								
	1910	1920	1930	1940	1950	1960	1970	1980	1990
1900	4.2	5.7	4.8	4.3	3.6	3.4	3.2	2.9	2.7
1910		10.2	5.4	4.5	3.4	3.2	2.9	2.7	2.5
1920			3.0	2.8	2.4	2.5	2.3	2.1	2.0
1930				2.4	2.1	2.3	2.2	2.0	1.8
1940					1.9	2.2	2.1	1.9	1.7
1950						2.7	2.2	1.9	1.7
1960							1.9	1.6	1.4
1970								1.3	1.1
1980									0.8

Sources: ●Net Generation 1900-1980: Appendix C. Net generation for 1900 was assumed to be approximately 2 billion kilowatthours, and for 1910, approximately 10 billion kilowatthours. ●Real Gross National Product: 1900-1980, U.S. Department of Commerce, Bureau of Economic Analysis, 1972=100. ●Projected 1990 ratios are derived from these sources and from the Energy Information Administration, *Annual Energy Outlook 1985* (February 1986).

¹⁵Energy Information Administration, *Annual Outlook for U.S. Electric Power 1985*, DOE/EIA-0474(85) (Washington, DC, August 1985), p. xi.

The increased use of robots by manufacturers extends the applications of electricity in the 1980's.

Table 7. Total End-Use Energy Consumption and Electricity Sales, by Sector
(Quadrillion Btu per Year)

Sector	1985*	1990	1995
Total U.S. Energy Consumption	74.8	80.4	84.3
Energy Consumption by Electric Utilities	26.6	30.5	34.9
End-Use Energy Consumption			
Residential	8.9	9.7	10.0
Commercial	5.9	6.5	6.7
Industrial	21.3	22.7	22.7
Transportation	20.0	20.1	20.3
Total End-Use Consumption	56.0	59.0	59.7
Electricity Sales by End-Use Sector			
Residential	2.7	3.1	3.5
Commercial/Other ^b	2.3	2.7	3.0
Industrial	2.9	3.3	3.8
Total Electricity Sales	7.9	9.0	10.3

* 1985 is considered a forecast year in this Outlook. Since its preparation, actual 1985 data for many variables have become available and are published in the Energy Information Administration, *Annual Energy Review 1985* (May 1986).

^b Other includes street lighting and the transportation sector.

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

Source: Energy Information Administration, *Annual Energy Outlook 1985* (February 1986).

Electricity demand growth is expected to show considerable regional variation. In the base case, the average electricity consumption growth rate between 1985 and 1995 is projected to range from a low of 2.1 percent a year in the New York/New Jersey region, to a high of more than 3.3 percent a year in the North Central, Northwest, and Western regions (Appendix A).

Generating Capacity

Projections of new generating capacity are based on current construction and plans reported by electric utilities; they also include additions estimated by EIA to be needed in order to meet demand but not currently included in utility plans.

Projected generating capacity values in this report differ in three respects from the nameplate capacity (manufacturer's rating) values previously published. First, these values now describe net summer capability, a value for most technologies (except hydroelectric) about 5 to 7 percent less than the nameplate capacity. Net summer capability is defined as the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by test at the time of summer peak demand. Second, the net summer capability value includes small amounts of inactive reserve capacity formerly excluded. Finally, projected values are net of expected capacity retirements, a feature absent from earlier projections.

Capacity is projected to grow at 1.2 percent a year, less than half the rate of growth of electricity demand (Table 5). More than 116 gigawatts of new generating capability are projected from the end of 1984 through 1995 (including almost 19 gigawatts in 1985), 99 gigawatts either under construction or planned by utilities, plus an additional 17 gigawatts estimated by EIA as needed after 1989. These additions are partially offset by almost 15 gigawatts of expected retirements. Expected additions of generating plants are greatest before 1988 and decrease significantly thereafter.

Including additions in 1985, new coal-steam capability of almost 46 gigawatts is projected to provide the largest share of new generating capability (40 percent), with nuclear generating capability additions adding almost 41 gigawatts (35 percent). Because no oil- and gas-fired steam plants are planned or under construction, this capability is projected to drop from 145 gigawatts in 1985 to 135 gigawatts in 1995 due to retirements. While only 4 percent of new capacity is projected to be pumped storage hydroelectric capacity, its additional 4.7 gigawatts from 1985 through 1995 represent a one-third increase in U.S. capacity of this type. An additional 4 percent of the increase in U.S. generat-

The undamaged Three Mile Island 1 nuclear reactor returned to commercial operation in 1985.

ing capacity is attributed to conventional hydroelectric capacity and other sources. Virtually all other additions are projected to be combustion turbines.

The rate of growth of nuclear-powered generating capability is projected to be much greater than that for other generating plant types, averaging almost 3.5 percent a year, compared to a net growth rate of less than 1 percent a year for all other types. As a result, nuclear generating capacity is expected to provide a greater share of electricity supply in many regions. More than 85 percent of projected nuclear capability additions are projected to be completed before 1990.

The projected electricity supply (capacity) growth rate from 1985 through 1995 is well below its actual growth rate from 1970 through 1984 and below the capacity growth rate projected in last year's Outlook. From 1970 through 1984 capacity increased at an average annual rate of 4.7 percent, one-third faster than electricity demand (Appendix C). Last year's Outlook projected a nameplate capacity growth rate of more than 1.4 percent a year from 1985 through 1995.¹⁶ Capacity is projected to grow much more slowly than electricity demand because existing capacity, built in anticipation of more rapid demand growth than now expected, is projected to be adequate to meet most electricity demand growth. Reductions in projected

¹⁶Energy Information Administration, *Annual Energy Outlook 1985*, DOE/EIA-0383 (85) (Washington, DC, February 1986), p. 29.

supply growth result from reduced expectations for increases in electricity demand for the outlook period.

Forecasts of planned new capacity additions (reported by utilities for 1985 through 1995) have been reduced from last year's Outlook, reflecting utilities' continuing adjustments to lowering demand growth projections. Overall, after adjusting for differences in capacity definitions used in this report from the previous forecast, expectations for planned capability additions from 1985 through 1995 have declined more than 11 percent since last year's forecast. About 10.5 gigawatts of planned coal-fired capability (about 20 percent) and 5 gigawatts of nuclear capability (over 10 percent) have been canceled or delayed beyond 1995 since last year's Outlook.¹⁷ As a proportion of planned additions, reductions are particularly sharp in the Northwest, Mid-Atlantic, New England, and Central regions. Absolute reductions are the greatest in the South Atlantic and Mid-Atlantic regions.

The EIA estimates that some regions may require more new capacity than currently planned in order to meet electricity demand adequately through 1995. Nationwide, this additional capacity growth requirement totals 17 gigawatts by 1995, about 17 percent more than currently reported by utilities for the outlook period (Table 5). These additions are projected to be needed after 1989 and to be concentrated in the New England, Mid-Atlantic, Central, West, and Northwest regions (Appendix A).

The EIA estimate of 17 gigawatts of additionally required capability is an approximation of needed utility actions beyond currently reported plans in order to meet electricity demand adequately through 1995. Means of meeting projected requirements, not explicitly represented in these projections, could also be used, such as extending the service life of existing capacity, increasing bulk power transfers, or introducing new generating technologies (see Chapter 4). Other measures, such as conservation, increased electricity imports, load management, cogeneration, decentralized generation, or improved transmission technologies, may also contribute substantially to reducing or meeting electricity demand through the forecast period.

Electric power imports are an important and growing source of electric power in certain regions of the country. Nationally, electricity imports (primarily from Canada) are expected to increase from 41 billion kilowatthours (kWh) in 1985 (1.8 percent of demand) to 67 billion kWh in 1990 and to 81 billion kWh in 1995, meeting almost 2.7 percent of total domestic electricity

demand in 1995. In the New England region, net electricity imports are expected to increase from 6.5 percent of demand in 1985 to more than 17.5 percent in 1995; similarly, in the New York/New Jersey region, net electricity imports are expected to increase from less than 14 percent of demand in 1985 to almost 19 percent in 1990, but fall to less than 10 percent in 1995. Net electricity imports are projected to grow from less than 4 percent of electricity demand in the North Central region in 1985 to 10 percent in 1995, although the region remains a major exporter of electricity to other U.S. regions.¹⁸

Electric Utility Fuel Use

Major changes in the fuels used to generate electricity have occurred since the 1973 oil embargo. Utilities have instituted programs to use more coal and nuclear energy, and to decrease dependence on more expensive oil and natural gas.

Coal-fired and nuclear generation are projected to provide most of the electricity generated in the United States from 1985 through 1995. Nuclear power stays in second place, behind coal, as a principal provider of U.S. electric power, a rank first achieved in 1984. Together, coal (55 to 57 percent) and nuclear power (15 to 20 percent) are expected to provide three-fourths of all generation. With the arrival of major coal-fired and nuclear capacity additions, the oil and natural gas share drops from 16 percent in 1985 to 13 percent in 1988. Their share increases again in the 1990's to nearly 16 percent, as growth of coal-fired and nuclear additions slows and as new oil- and gas-fired turbines are built to meet peak demands. Although electricity generated from hydroelectric and other sources (geothermal, wood, waste, solar energy, and wind) is projected to grow absolutely, their share of total generation decreases from nearly 12 percent of total generation in 1985 to 10 percent in 1995 (Table 5).

Because generating capacity is projected to grow much more slowly than demand, existing capacity is expected to be utilized more intensively.¹⁹ Coal-fired plants' utilization rates are projected to increase from an average of 59 percent in 1985 to 64 percent in 1995; nuclear, from 53 percent to 63 percent; and oil- and gas-fired steam capability, from 26 percent to 36 percent. These higher operating factors indicate fuller and more efficient use of existing capability and assume that

¹⁷Energy Information Administration, *Annual Outlook for U.S. Electric Power 1985*, p. 29 and Appendix C, Tables C2-C11, pp. 66-75.

¹⁸Energy Information Administration, *Intermediate Future Forecasting System (IFFS)*, IFGMMM.D1118851.

¹⁹

$$\text{Utilization Rate} = 100 \times \left(\frac{\text{Annual Generation}}{\text{Capacity} \times (\text{Hours in the Year})} \right) \quad (1)$$

where 8,760 = total hours per year.

plants can achieve performance levels similar to those realized in earlier periods.

Choice of primary fuels varies across regions, as a function of availability of generating plant types, availability of fuels, load characteristics, and intensity of capacity use. For example, the New England and New York/New Jersey regions rely primarily on oil-fired and nuclear generation; the Western region primarily uses natural gas and hydroelectric power, while the Northwest depends on hydroelectric power. All other regions depend primarily upon coal-fired generating systems.

Electricity Prices

Real electricity prices nationwide are projected to decline over the Outlook period. Real electricity prices (in 1985 dollars) rise from 66 mills per kWh in 1985 to a peak of 68 mills per kWh in 1987, as the majority of units under construction come on line, and then decline to 61 mills per kWh in 1995. Real electricity prices from 1985 through 1995 decline at an average annual rate of 0.9 percent per year (Table 5).

The projected decreases in electricity's price can be explained in terms of its price components—fuel, operation and maintenance, and capital.

The fuel component of electricity's price is projected to decline through 1988 and then increase through 1995 to levels higher than in 1985. From 1985 through 1988, the fuel component declines as new coal-fired and nuclear units begin operation and prices for oil and natural gas decrease. After 1988, fuel costs are projected to increase, rising from 33 percent of electricity's price through 1990 to 40 percent in 1995.

The operation and maintenance (O&M) component of electricity's price is projected to increase slightly from 1985 to 1990, and then decline from 1990 to 1995 as it is distributed over the more intensively utilized capital stock, lowering the overall cost per unit of electricity generated. Although the O&M component is projected to decline at an average rate of 0.4 percent a year, its relative share of electricity's price is expected to remain about 25 percent.

The capital component of electricity's price is projected to decrease because of the combined effect of two factors: first, the size of the rate base decreases, and second, the sales base over which the capital costs in the rate base are distributed increases over the projection period.

The rate base is the measure of electric utility investment used by regulators in determining electricity prices (see Chapter 2, Revenue Requirements). In real terms, the value of the rate base for all privately and publicly owned electric utilities is projected to decline

from \$297 billion in 1985 to \$251 billion in 1995 (Table 8). The change in the value of the rate base is attributable to three factors. First, the value of electric plant in service is projected to grow only \$52 billion, much more slowly than in recent years, from \$373 billion in 1985 to \$425 billion in 1995 as new plants are completed and become operational. Second, accumulated depreciation, which represents a reduction in the value of the rate base, is projected to increase substantially, from \$108 billion in 1985 to \$173 billion in 1995, more than offsetting any growth in electric plant. Accumulated depreciation reflects reductions in the value of both existing and new assets over time. The projected increases in accumulated depreciation are attributable to the diminished value of high-cost assets added in the mid to late 1980's. Third, the value of construction work in progress (CWIP), representing new but incomplete construction allowed in the rate base, is projected to decrease from \$46 billion in 1985 to \$10 billion in 1995, indicating further slowdowns in new utility investment growth. Between 1985 and 1990, 57 gigawatts of capital-intensive coal-fired and nuclear-powered plants are to be added to electric plant in service. For the period from 1990 through 1995, such additions total only 30 gigawatts. As a result of slowed growth of utility plant and CWIP, along with a large increase in the value of accumulated depreciation, the projected value of the rate base declines and results in a lower value for the capital component of electricity prices.

Also contributing to a decrease in the capital component of electricity's price is the projected increase in electricity sales, from 2,317 billion kWh in 1985 to 3,026 billion kWh in 1995. As a result, the value of the decreased rate base is projected to be distributed over a larger quantity of electricity sales, further lowering the capital component of electricity's price. This effect is particularly important for 1990 when prices decline compared to 1985, even though the rate base remains about the same.

The projected path of electricity prices and their price component both encourages and warns electricity planners over the remainder of the 20th century. Using existing capacity rather than adding new units contributes to lower electricity prices; at the same time, however, delays in planning and building new baseload capacity could lead to higher fuel and capital costs later, resulting in higher electricity prices.

The predominantly investor-owned utilities in the Northeast region that depend on petroleum or natural gas have the Nation's highest electricity prices, while the predominantly Federally-supplied and hydroelectric utilities in the Northwest have the Nation's lowest electricity prices. Because of dependence on oil and natural gas, electricity prices are expected to fall less rapidly than the national average in the New England, New York/New Jersey, Middle Atlantic, and West regions. In regions that rely more on coal and hydroelectric power, such as the South Atlantic, North Cen-

Table 8. Selected Rate Base Accounts, 1985-1995
(Billion 1985 Dollars)

Account	1985 ^a	1990	1995
Electric Plant in Service	373	437	425
Accumulated Depreciation	108	149	173
Net Electric Plant	265	288	252
Construction Work in Progress	46	26	10
Subtotal	311	314	262
Other Rate Base Accounts ^b	14	15	11
Total Rate Base	297	299	251

^a 1985 is considered a forecast year in the Outlook.

^b These accounts include working capital.

Source: Energy Information Administration, National Utility Financial Statement Model, IFGMMM.D1118851.

tral, Central, and Northwest, electricity prices are projected to drop more rapidly.

Projections for the West illustrate the effects of petroleum costs on electricity prices. There the fuel component of real electricity prices drops at the Nation's fastest rate from 1985 through 1990 because of proportional shifts away from petroleum and natural gas toward nuclear power, but rises the most quickly after 1990 as it becomes more dependent upon expensive gas and oil to meet electricity demand.

The effects of capacity growth on prices are best illustrated by the Central, Northwest, and Southwest regions. With the slowest projected rates of capacity growth in the Nation, the Central and Northwest regions are projected to experience the largest drops in the capital component of electricity price. On the other hand, capacity growth above the national average is projected in the Southwest region, yielding only slight decreases in electricity's capital costs and prices.

The financial condition of investor-owned electric utilities (IOU's) is projected to improve during the forecast period, because the utility construction activities are declining. As a result, utility borrowing and financing obligations are expected to decrease steadily in most regions of the country over the period.

Interest coverage, a ratio of utility earnings to interest payments, is projected to improve from 2.4 in 1985 to 2.8 or more beginning in 1988, which indicates improved ability of IOU's to meet interest obligations. Similarly, the internal financing ratio, describing internal cash flow as a percentage of construction expenses, is projected to rise from less than 70 percent in 1985 to nearly 120 percent in 1995, indicating ability to finance construction from internal funds. In addition, the proportion of electric utility earnings attributed to incomplete construction is projected to decline. In 1985 the estimated percentage of earnings imputed to

be earned from incomplete construction comprised about 53 percent of total earnings; by 1995 the percentage is projected to fall below 18 percent. Similarly, construction work in progress (CWIP), which is the value of expenditures for plants that are incomplete and not yet in service, is projected to fall from 24 percent of net plant in 1985 to less than 8 percent in 1995, a drop of about 75 percent. Finally, the rate of return on equity to IOU's is projected to improve, from less than 15 percent in 1985 to more than 16 percent in 1995.²⁰

The projected improvements in the financial condition of the electric utility industry through the forecast period indicates a further recovery of the industry over the period. However, individual privately owned utilities, particularly those continuing to incur the costs of major new construction, may experience financial difficulties. Further, the improvement is contingent upon slowed capacity growth and ability to meet unexpected demands.

Sensitivities

It is unlikely that all the base case assumptions will, in fact, be realized. Therefore, in addition to providing the forecasts of the major electricity variables (demand, price, and capacity), the relative roles of some important factors affecting electricity markets are described. The market effects of changes in the overall rate of economic growth (a principal electricity demand variable) and of reduced rates of new generating capacity growth (the major supply variable) are examined to determine their contribution to projections (Table 9).

²⁰Energy Information Administration, National Utility Financial Statement Model, IFGMMM.D1118851.

Changes in Overall Economic Growth

The low, base, and high economic growth cases contain various assumptions about world oil prices and economic growth, with low economic growth corresponding to world oil prices higher than in the base case, and high economic growth coupled with world oil prices lower than in the base case (Table 9).

Overall, changes in electricity demand are projected to follow changes in the rate of economic growth, but to a lesser degree. While average economic growth is assumed to vary by plus or minus 0.4 percent a year from the base case, resultant electricity demand growth is projected to vary an average of plus or minus 0.2 percent a year (Table 4). A return to a ratio of electricity demand to GNP greater than 1 (Table ES1) is projected to occur only under low economic growth conditions.

Among the three major electricity end-use sectors (residential, commercial, and industrial) projected growth rates in industrial electricity consumption are most affected by changes in rates of economic growth. Industrial electricity consumption changes at about the same rate as economic growth. Residential and commercial electricity end-use growth rates are less responsive, declining only an average of 0.1 percent a year in the low economic growth case, and increasing only an average of 0.2 percent a year in the high economic growth case (Table 5 and Figure 3). Without notable exception, projected changes in all regional electricity demand growth rates follow this national pattern (Appendix A, Tables A2-A11).

Oil- and gas-fired generating capacity, which is more expensive to operate, is typically the last pressed into service in times of higher demand and the first withdrawn when demand falls. In the low economic growth case (high world oil price), oil- and gas-fired generation is projected to grow only 1.5 percent a year, comprising only 14 percent of total 1995 electricity generation. In the high economic growth case (low

world oil price), oil- and gas-fired generation is projected to increase at an average annual rate of 3.5 percent and comprises a 17-percent share of total net generation.

The sensitivities also indicate utilities' response to decreases in long-term world oil prices (Table 9). As world oil prices drop, utilities increase oil-fired generation, both to meet increased electricity demand consistent with lower world oil prices and also in place of natural gas-fired generation. In the high world oil price case, oil is projected to contribute only 4 percent of total electricity generation; in the low world oil price case, oil is projected to provide 8 percent of electricity generation. More than 90 percent of the increased electricity demand between the low and high economic growth cases is projected to be provided by oil-fired generation. On the other hand, gas-fired generation is projected to decline most as world oil prices fall, despite growth in total electricity demand. As world oil prices drop in the scenarios examined, the natural gas generation share drops to about 9 percent, as utilities switch dual-fired units from natural gas to oil and substitute oil-fired units for natural gas units. Under the scenarios examined, little switching from other fuel sources (coal, hydroelectric, and nuclear) is expected, given the expected cost advantages of these sources over both oil and natural gas for baseload generation.

Electricity prices change very little under the economic growth cases analyzed. Electricity prices nationwide decline slightly more rapidly under low economic growth despite higher world oil prices, primarily because oil and natural gas use drops more than enough to offset increases in unit fuel costs. Furthermore, under lower economic growth, requirements for new generating capacity also decline, reducing the capital share of electricity's price. On the other hand, higher rates of economic growth require both more extensive oil and natural gas use and additional generating capacity, raising both the fuel and capital components of electricity's price. The overall real electricity price difference in 1995 between the low and high economic growth cases is less than 1 percent (Table 5). Only in the heavily oil-dependent regions of New England, New York/New Jersey, and Middle Atlantic do the

Table 9. Projected Gross National Product and Assumed World Oil Prices, 1985-1995
(1985 Dollars)

Case	Gross National Product			World Oil Price ^a		
	1985 ^b	1990	1995	1985	1990	1995
Low	3,882	4,449	4,940	27	32	37
Base	3,882	4,526	5,128	27	27	30
High	3,882	4,632	5,313	26	22	25
High Electricity Demand	3,887	4,750	5,517	26	22	25
Reduced Capacity	3,882	4,526	5,128	27	27	30

^a The cost of imported crude oil to U.S. refiners.

^b 1985 is considered a forecast year in this Outlook.

Sources: ^aLow, middle (base), and high cases: Energy Information Administration, Annual Energy Outlook 1985 (February 1986). ^bHigh demand and reduced capacity cases: Energy Information Administration, Intermediate Future Forecasting System (IFFS), IFGMLX.D1127851 and IFGMMM.D1118852.

Figure 3. End-Use Electricity Consumption

Source: Energy Information Administration, *Annual Energy Outlook 1985*, February 1986.

assumed world oil price effects predominate, yielding higher 1995 average electricity prices under conditions of low overall economic growth and lower prices under assumptions of high economic growth, although the differences never exceed 4 percent from the low to the high case.²¹ Only in the Southwest region, in the high demand growth case, do real 1995 electricity prices exceed the 1985 price, and then by less than 1 percent, primarily because of increased fuel costs (Appendix A, Tables A2-A11).

Changes in the rates of overall economic growth clearly affect the projected adequacy of current and planned electricity supplies nationwide, and change requirements for measures beyond current plans in order to meet electricity demand. Under all three economic scenarios, either some additional generating capacity or other measures appear to be required to meet demand reliably through 1995. Under low economic growth, the equivalent of nearly 13 gigawatts of additional capacity, about 13 percent more than currently planned, is projected to be required; under base case assumptions, an additional equivalent of more than 17 gigawatts is estimated to be needed, and under high economic growth, the equivalent of more than 25 additional gigawatts could be required, or 26 percent more than currently planned for the forecast period. In the high economic growth case, additional new capacity

beyond that currently planned to be needed is projected by 1989. Other measures, such as increased electricity imports, additional power exchanges and improved transmission services, conservation, cogeneration, or electric power production by firms other than electric utilities, could also help meet demand (Table 5).

The need for additional generating capacity beyond currently announced plans varies among regions (Appendix A, Tables A2-A11). The South Atlantic, Midwest, Southwest, and North Central regions appear to require little or no additional capacity through 1995, even under assumptions of growth higher than in the base case.

The Mid-Atlantic, Central, and West regions, in contrast, require substantial new capacity by 1995, even in the low growth case. In the low growth case, the Mid-Atlantic region requires capacity equal to currently reported plans. In the same case in the Central and West regions, further capacity equal to between 35 and 40 percent of current plans is projected to be required. All three regions could require even greater additional capacity under higher growth cases.

The remaining areas, the New England, New York/New Jersey, and Northwest regions, have more varied supply needs through 1995. With low economic

²¹In the high growth case, the capital component of electricity's price rises in some regions despite the apparent absence of new capacity and the more intense use of existing capacity, which normally result in a lower unit capital cost component. This higher capital component is the result of new capacity that is required to meet demand after 1995.

growth, currently planned additions appear adequate for the New England, New York/New Jersey, and Northwest regions. In the base case, however, the New England region requires additions about one-third greater than currently planned. In the high case all three regions are projected to need additional capacity (New England, an additional 75 percent over current plans; New York/New Jersey, 30 percent; and the Northwest, nearly 50 percent).

High Electricity Demand

EIA also examined the electricity market effects of economic growth rates higher than assumed in the earlier cases, induced by higher industrial electricity demand (and lower-than-base-case world oil prices). EIA examined a scenario in which GNP grows at an average annual rate of 3.6 percent and electricity demand grows at an average annual rate of 3.2 percent (Table 4).

Overall, results of this high electricity demand scenario extend results of the high economic growth case. Under the high electricity demand case, existing and currently planned capacity are not able to meet all demand. Approximately 40 percent more new generating capacity than currently planned, 40 gigawatts, is projected to be required. The Midwest region, unaffected under the other scenarios, is projected to require almost 3.1 gigawatts more new capacity than currently planned. The South Atlantic, Southwest, and North Central regions are projected to require little or no additional capacity.

This higher electricity demand growth rate indicates far greater dependence on oil, partially because of projected requirements for oil-fired turbines, and also because of the increased use of oil in dual-fired boilers resulting from the assumption of lower-than-base-case world oil prices. Compared to the base case, oil-fired generation in 1995 in the high electricity demand case increases almost 90 percent, rising from 5 percent of total generation to 9 percent in 1995, as increased oil use accounts for almost 90 percent of the overall additional required generation over the base case.

In the high-electricity-demand case, electricity prices are projected to decline through 1995, but more slowly than in the other cases, at an average annual rate of 0.6 percent. By 1995, real electricity prices are projected to be only slightly above the base case prices, but still below the 1985 price. In this high-electricity-demand case, 1995 prices are projected to be slightly higher than in 1985 in only two regions, the Middle Atlantic and the Southwest, in response to higher fuel costs.

Reduced Capacity Additions

To examine the effects of further reductions in new generating capacity additions on national electricity supply over the forecast period, EIA has assumed that coal-fired and nuclear capacity planned but not yet under construction will not be completed before 1995. Nearly 25 gigawatts, or one-fourth of currently anticipated capacity additions, are assumed canceled or postponed under this scenario; furthermore, nearly 95 percent of the reduction occurs after 1990, since plants scheduled in this time period are the least likely to be currently under construction. Overall, planned coal-steam additions are reduced more than 40 percent, from 46 gigawatts in the base case to 27 gigawatts. Of currently planned nuclear capability (almost 41 gigawatts), 5.5 gigawatts are assumed canceled, a decrease of more than 13 percent.

In the reduced capacity growth case, electricity demand remains about the same as the base case. However, continued cutbacks in baseload nuclear and coal-fired additions imply greater reliance upon existing and new oil- and gas-fired capacity. More than half the assumed decrease in capacity would have to be replaced, particularly after 1990. An additional 30 gigawatts of new turbine capacity are projected to be required, compared to 17 in the base case. Oil- and gas-fired generation in 1995 is projected to rise from about 500 billion kilowatthours in the base case to just over 600 billion kilowatthours in the reduced capacity growth case, about 19 percent of U.S. total generation (Table 5).

The path of electricity prices in this case emphasizes the short-run price advantage of construction cutbacks in exchange for higher prices in the longer term. For almost the entire forecast period, reduced capacity additions reduce electricity prices about 1 percent below prices in the base case, as lower capital costs more than offset increased fuel costs. However, by 1995, projected prices exceed those of the base case, in response to growing fuel costs and capital costs of new replacement capacity.

In regions with significant cutbacks, the extent to which replacement capacity is not needed suggests the extent to which the regions may be able to tolerate capacity growth reductions through 1995. For example, the South Atlantic, North Central, Southwest, and Midwest regions may be able to tolerate reductions in capacity growth. On the other hand, assumed reductions in the Mid-Atlantic, Central, West, and Northwest regions appear to require roughly equal replacement capacity.

Price patterns vary a great deal across regions, depending upon the relative magnitudes of the capacity reductions, demand for replacement capacity, fuel costs, and quantity and costs of alternate supply sources. In some regions, prices remain slightly below projected prices in the base case, as savings in capital costs outweigh

increased fuel costs; in other regions, prices are projected to exceed base-case expectations. The South Atlantic, Central, Midwest, and Northwest regions are projected to enjoy lower prices and higher demand over the forecast period as a consequence of reduced capacity. The Southwest, North Central, and West regions incur increased prices because increased fuel costs outweigh savings in capital costs (Appendix A, Tables A2-A11).

Summary

In general, this Outlook projects moderate growth in U.S. electric utility demand from 1985 through 1995

(2.7 percent). Electricity demand is expected to grow at about the rate of overall U.S. economic growth. The Outlook projects a reduced rate of capacity growth of less than half the growth rate of electricity demand, as utilities are projected to meet most demand growth with existing capacity. Some regions are projected to require either additional capacity (beyond currently reported plans) or equivalent measures in order to meet all demand through 1995.

National electricity prices are projected to decline over the outlook period, at an average of less than 1 percent a year. Decreases in the per unit of electricity costs of new generating capacity outweigh increases in the use of more expensive oil and natural gas. Finally, financial conditions for investor-owned electric utilities are generally projected to improve as a result of declining rates of new capital investment.

4. Factors Affecting the Outlook for U.S. Electric Power

Chapter 3 presents a range of EIA projections for electricity supply, demand, and prices for the 1985 through 1995 Outlook period. This chapter identifies and briefly describes additional factors that may affect U.S. electricity markets over the forecast period.

Life Extension of Coal-Fired Power Plants

Introduction

Coal-fired power generation provides the largest share of total U.S. electric generation, and is expected to continue to provide more than half of total U.S. electricity through the mid 1990's. High construction and financing costs and environmental and siting constraints, coupled with low load growth projections, discourage construction of new power plants. In coming years, a continued lull in construction may result in an increasing share of generation coming from fossil-fuel units older than 30 years, almost half of which are coal-fired units. By 1995 over 60 percent of all coal-fired power units will be more than 30 years old; they will comprise approximately 26 percent of total coal-fired generating capability, compared to approximately 10 percent in 1985 (Figure 4).²²

As an alternative to new plant investment, many utilities have begun research and planning programs to upgrade and refurbish their older units for efficiency improvements and extended life. Greater reliance on older, smaller units has the advantage of permitting more flexible output to meet changing demand cycles. Smaller units are better equipped to vary output than the larger baseload units. Because coal-fired units usually have the lowest generating costs among fossil-fuel units on a system, they will frequently be a utility's first candidate for refurbishment. Life extension programs are also being considered for hydroelectric, nuclear, and oil- and gas-fired units, including the conversion

of oil-fired plants to gas. With programs of upgrading and modernization, utilities may be able to meet future demand with greater flexibility, extending the average life of their coal-fired units 20 to 30 years.

Characteristics of Plant Life Extension

Compared with the construction of new generating capability, upgrading and plant life extension may be cheaper sources of additional electricity generation. The concept of extending the reliable life of power plants and acquiring more efficient and increased generating capacity is a direct evolutionary outcome of the current capacity surplus and the high financial risk of new plant construction.

Upgrading and life extension encompass a review of a system's entire structure to find the lowest cost economically and financially feasible means of generation. A typical program entails a thorough review of plant design, equipment, performance, and operation and maintenance procedures systemwide. In deciding the means and extent of a refurbishment, the primary focus is on a given plant's expected capability, the system's cost for replacement electricity, and the system's cost for replacement capacity. The resultant project may involve modernization to incorporate technological advances made after the original installation of the plant, changes in operations and maintenance procedures, and refurbishment or replacement of plant components.

A crucial determinant in life extension planning is its application as a means to reduce the probability of forced outages in the near and distant future. Most coal-fired power plants are designed for an anticipated lifetime of 30 to 40 years. According to data compiled by the North American Electric Reliability Council, power plants with nameplate generating capacity between 50 and 200 megawatts (likely candidates for refurbishment) begin to become less reliable after 20 years of operation. As shown in Figure 5, after 30 to

²²Energy Information Administration, Generating Unit Reference File (GURF) (Washington, DC, December 16, 1985).

Figure 4. Age and Megawatt Capability of Coal-Fired Steam Units

Source: Energy Information Administration, Generating Unit Reference File, December 16, 1985.

35 years, their forced outage rate accelerates sharply and the duration of the forced outages increases.²³

Greater attention to the reduction of forced outages improves a utility's cost effectiveness. Aside from lower energy replacement costs, utilities can meet demand with lower required reserves and greater reliability.²⁴

For a major component being considered for refurbishment or replacement, life-extension analysis reviews that component's probability of failure, the consequences of the failure, the expected results from upgrading, and the expected benefits in terms of dollars saved. Many components may require low capital outlays that have a rapid payback or are immediately cost-effective. For example, an automatic control system to accelerate turbine-generator startup time may reduce the cost of generating power through more efficient generator startup.

Regulatory Requirements

Two significant regulatory factors in assessing the benefits of a life extension program are the expected level

of sulfur emissions from a refurbished coal-fired unit, and the cost of the refurbishment.

The New Source Performance Standards (NSPS) mandated by the Clean Air Act, which stipulate a ceiling limit on sulfur dioxide (SO_2) emissions from new coal-fired power plants on which construction or modification began after 1971, generally do not apply when existing units are upgraded or refurbished. If a refurbishment does not incorporate major modifications that increase the plant's emission levels beyond those occurring under its originally permitted specifications, it need not comply with NSPS regulations, even if the refurbishment does increase current emission levels because of increased generation.

Reconstruction as defined by NSPS regulations includes major component replacement or reconstruction exceeding 50 percent of the cost of an entirely new boiler. If refurbishment costs for a coal-fired boiler and other capital costs do not exceed 50 percent of the cost of a new boiler, the plant is not subject to the NSPS regulations. If refurbishment costs are greater than 50 percent of the cost of a new boiler, the plant is catego-

²³H. G. Stoll, "The Economics of Power Plant Upgrading," paper presented at the Power Plant Life Extension, Renovation and Upgrading Workshop, American Public Power Association (Omaha, Nebraska, May 22, 1984), p. 7.

²⁴A. F. Armor and others, "A Strategy For Fossil Power Plant Life Extension," paper presented to the American Power Conference (Chicago, Illinois, April 22-24, 1985), pp. 6-7.

Figure 5. Forced Outage Rate of Coal-Fired Steam Units

Source: General Electric Company, H.G. Stoll, "The Economics of Power Plant Upgrading," May 22, 1984.

rized as reconstructed and must comply with the NSPS emission control standards. Reconstruction costs refer to costs related to the capital costs of a replaced boiler, and are not clearly defined for costs over time. The legal parameters that define plant reconstruction costs relating to NSPS compliance have not been clearly defined. Thus, it is uncertain if a phased-in refurbishment of a boiler and other major components over an extended period that exceeds 50 percent of the cost of a new boiler would have to comply with NSPS regulations, if it was not initially reported as a single project.

Cost Comparisons With New Capacity

Required installation of a flue gas desulfurization (FGD) system on an older coal-fired unit could dis-

courage the implementation of a life extension program. However, even with an FGD retrofit costing approximately \$200 to \$300 per kilowatt for medium-sulfur coal,²⁵ the cost per kilowatt for a life extension program could still be substantially less than the cost of constructing a new unit. A comparison of the costs of building a new 500-megawatt coal-fired unit with the costs of a program extending the life of two 40-year-old 350-megawatt coal-fired units providing the same total generation indicates that it may be more cost-effective to refurbish the older plants, even with the addition of FGD scrubbers. As shown in Table 10, the cost of building a new plant could be over \$15 million a year more than refurbishing and extending

²⁵D.B. Garvey, D.G. Streets, and T.D. Veselka, "The 'Control-Or-Retire' Strategy For Reducing Sulfur Dioxide Emissions From Power Plants," Technical Memo prepared for Office of Environmental Analysis, U.S. Department of Energy, Report No. ANL/EES-TM-283, Argonne National Laboratories (October 1984), p. 1.

Table 10. Comparison of Annualized Costs of New and Refurbished Generating Units

(Millions of 1980 Dollars per Year)

Plant Costs	One New 500-Megawatt Unit	Two Old 350-Megawatt Units
Capital	53.6	—
Refurbishment	—	23.0
Fixed Operation and Maintenance	3.5	6.2
Flue Gas Desulfurization	19.5	32.6
Total	76.1	60.8

Source: Argonne National Laboratory, The "Control-or-Retire" Strategy for Reducing Sulfur Dioxide Emissions From Power Plants (Argonne, Illinois, October 1984), p. 30.

the life of two existing units, including retrofit of FGD scrubbers.²⁶ The estimated annualized cost (20 years) of refurbishing two existing units, excluding FGD and the fixed share of operation and maintenance (O&M) costs, is \$23 million a year, or approximately \$350 per kilowatt, while the capital cost (including interest during construction) of the new unit is \$53.6 million a year, approximately \$1,190 per kilowatt. However, much greater FGD costs for the older units, along with higher O&M costs, offset a large proportion of the capital savings of the refurbishment option.

However, the long-term cost effectiveness and efficiency of an FGD retrofit for a coal-fired plant near retirement compared to long-term benefits of a new, more efficient coal-fired power plant have not been fully assessed using actual data. Furthermore, the estimated life extension costs do not include the increased operation and maintenance costs reflected in the new management approaches that life extension programs would necessitate.

Current Developments

Among the most likely candidates for life extension are units of utilities already considering expansion.

- The Electric Power Research Institute is sponsoring six life extension projects, including the development of generic guidelines for decisionmaking and implementation of life-extension strategies. Some of the utilities participating in the program include Boston Edison Company, Consumers Power Company, Niagara-Mohawk Power Corporation, and Pacific Gas and Electric Company.²⁷

²⁶Garvey, Streets, and Veselka, pp. 28-30. The new 500-megawatt unit is assumed to operate at 60-percent capacity, while the two 40-year-old 350-megawatt units each operate at 43-percent capacity.

²⁷A.F. Armor and others, "A Strategy For Fossil Power Plant Life Extension," pp. 5-6.

²⁸Office of Technology Assessment, *New Electric Power Technologies: Problems and Prospects for the 1990s* (Washington, DC, July 1985), p. 140.

²⁹Conversation and correspondence with H. M. Hall, Assistant Vice President, General Planning, American Electric Power Service Corporation (November 26-27, 1985).

- Cincinnati Gas & Electric, Potomac Electric Power, Pennsylvania Power & Light Company, and Georgia Power each have invested substantially in life extension projects for one or more of their fossil-fueled units. Duke Power, Florida Power, and the Tennessee Valley Authority each will close down units scheduled to be refurbished and reactivated in the 1990's.²⁸
- Colorado Ute Electric Association, Northern States Power, and Wisconsin Power and Light are conducting life extension projects that include an atmospheric fluidized-bed boiler retrofit.
- The American Electric Power Service Corporation (AEP) has a life extension research and development project underway to study one of its steam generating units that is about 30 years old, as a prototype of its typical unit, and has made tentative plans not to shut down any of its steam generating units before the year 2000. By the year 2000, over half of AEP's 55 operating steam generating units will be more than 40 years old.²⁹

Summary and Conclusions

Utility upgrading and life-extension programs may be less costly than constructing new power plants, given the present financial risk and regulatory constraints. As managerial and technological approaches become more developed, life extension may become an integral component of all system maintenance and operations as a means to lower electric rates. Adjusting projections of future electric capacity to reflect the extended lives of coal-fired units may still be premature while most programs are still in their planning stages.

Environmental and regulatory constraints on the construction of new coal-fired units may serve as an added incentive to the implementation of life extension programs. It may be more cost-effective for a utility to refurbish existing plants than to attain regulatory approval for construction on a new site and to abide by regional and Federal environmental emission limits.

Bulk Power Transactions

Bulk power transactions are the sale, purchase, and interchange of electricity among electric utilities.³⁰ These transactions primarily serve three purposes:

1. Increasing the reliability of electricity services by providing support during emergencies and by sharing capacity to reduce reserve requirements for individual utilities
2. Reducing capacity costs by allowing one utility's surplus capacity to be used to defer building new capacity in another utility, and by permitting the construction of more efficient generating units that might otherwise be too large for a single utility
3. Increasing the efficiency of utility operations by exploiting load diversity and lower cost generation to displace generation from oil- and gas-fired power plants.

The years following the oil embargo saw bulk power transactions increase faster than generation or sales to final customers (Table 11). Between 1973 (the last year

before the sharp increase in fuel prices) and 1984, net generation by investor-owned utilities increased at an annual average of 2.0 percent. Bulk power purchases (from other utilities, cogenerators, small power producers, etc.) increased at a rate of 3.5 percent per year. Sales to ultimate customers increased at an annual rate of 2.4 percent, while sales for resale increased at the rate of 3.2 percent. Interchanges, which include transfers in kind and other forms of transactions that do not involve monetary compensation, also increased. Receipts increased by 4.0 percent and deliveries by 3.0 percent. At the same time, wheeling (transmission by third parties) increased by more than 11.0 percent per year (11.7 percent increase in energy received and 11.4 percent increase in energy delivered).³¹

The cause of this increase in bulk power transactions was the severe increase in fuel prices, especially for fuel oil and, to a lesser extent, natural gas. Utilities that depended on fuel oil or natural gas for a large part of their generation purchased lower cost power from utilities with coal-fired, nuclear, and hydroelectric capacity. Even utilities that use coal or nuclear fuel for baseload generation had incentives to exploit seasonal and daily diversity to reduce use of oil- or gas-fired peaking units.

While bulk power transactions continue to displace oil- and gas-fired capacity, additional transactions are likely to occur as utilities with available surplus capacity sell power to other utilities seeking to defer construction of new power plants. The 1980's have seen escalating power plant construction costs replacing rising fuel prices as the primary source of higher electricity rates. Combined with existing excess capacity, the rising cost of new baseload capacity creates incentives for utilities (and regulators) to look for alternative power sources

Table 11. Generation, Sales, and Bulk Power Transactions Involving Investor-Owned Utilities, 1973 and 1984
(Billion Kilowatthours)

Sales/Transactions	1973	1984	Rate of Growth
Net Generation	1,458	1,814	2.0
Purchases	232	337	3.5
Sales to Ultimate Consumers	1,341	1,739	2.4
Sales for Resale	237	336	3.2
Interchanges - In (gross)	258	399	4.0
Out (gross)	246	342	3.0
Transmission for/by Others (Wheeling)			
Received	51	172	11.7
Delivered	52	171	11.4

Source: Energy Information Administration, *Financial Statistics of Selected Electric Utilities, 1984* (January 1986) and 1982 (February 1984).

³⁰Energy Information Administration, *Interutility Bulk Power Transactions*, DOE/EIA-0418 (Washington, DC, October 1983) provides a detailed description of bulk power transactions, their economic basis and how they fit into utility operations.

³¹Transactions involving publicly owned utilities (municipals, cooperatives, State, and Federal agencies) are included if one party to the transaction was an investor-owned utility. Transactions between publicly owned utilities exclusively are not included in these data.

Figure 6. Hypothetical 100-Megawatt Power Transfer over Parallel Paths from Utility A to Utility B

Source: North American Electric Reliability Council, David R. Nevins, "Overview of Electric Power Transmission in North America," September 1985.

or to find buyers for capacity that is temporarily in excess of loads. In some cases, bulk power sales are the only way that utilities can recover the costs of generating units that have been excluded from the rate base by State regulators, such as Colstrip units 3 and 4 in Montana or the Susquehanna nuclear power plant in Pennsylvania. The increase in cogeneration and small power production also provides additional power for bulk power transactions.

There are, however, constraints on the expansion of such transactions. The existence of excess capacity has created something of a "buyer's market," with utilities and other power producers competing for sales to municipal and cooperative distribution-only utilities and large industrial consumers. Such competition, however, conflicts with the franchised monopoly concept of public utilities under which a utility is granted the exclusive right to sell electricity within its service territory. Utilities that face the loss of customers have argued that their other customers would see rate increases if some customers were allowed to switch suppliers. The purchasers in this case argue that the utilities are unfairly attempting to preserve their monopoly at the expense of the publicly owned utilities and some customers.³²

Regardless of the economic and institutional factors, the critical factor constraining expansion of bulk transactions in the short run is the ability of the transmission network to carry additional power. Today, many segments of the transmission network are being loaded at or near their maximum safe operating levels virtually around the clock.³³ In order to prevent large-scale service disruptions, such as the 1965 Northeast blackout, the utility industry has established operating procedures that set limits on the use of transmission capacity (sometimes less than physical capacity).

The issue of transmission capacity is enormously complicated by the characteristics of integrated networks. Power flows through an alternating current network strictly according to the electrical characteristics (i.e., line loadings, impedances, etc.) of the system at the time of the power transfer. In particular, power flows over all transmission paths between the source (i.e., the generator) and the destination as illustrated in Figure 6. Figure 6 represents the sale of 100 megawatts of power by utility A to utility B. Only part of this 100 megawatts flows along the most direct path between A and B. The rest flows along other paths and through the transmission systems of other utilities. If, for example, utility D's transmission system is loaded to its maxi-

³²This controversy has been the subject of various conferences and position papers, and has been extensively aired in response to a Notice of Inquiry issued by the Federal Energy Regulatory Commission (Docket No. RM85-17-0000 (Phase 1)) (May 30, 1985).

³³David R. Nevins, "Overview of Electric Power Transmission in North America," paper presented at the Electricity Consumers Resource Council Seminar on Wheeling (Washington, DC, September 1985). Mr. Nevins represented the North American Electric Reliability Council.

Increased use of bulk power transfers is expected to help meet electricity needs over the Outlook period.

imum safe operating capacity before the transfer from A to B, then this transfer cannot take place without compromising the integrity of D's transmission system. Under operating procedures designed to prevent cascading blackouts (such as the 1965 Northeast blackout), the transfer from A to B would not be allowed.

Transmission capacity constraints often extend beyond the transmission links between transacting utilities. Expanding transmission capacity often requires the cooperation of a number of utilities, some of which are not directly involved in planned transactions. There is the further problem of deciding who will pay for new transmission capacity among utilities that are only indirectly involved in transactions (such as utility D in the example).

None of this means that utilities are not going to expand transmission capacity and increase bulk power transfers. Utilities in Florida have recently increased to 2,000 megawatts the capacity of transmission lines link-

ing them with the Southern Company (in Georgia) in order to increase purchases of coal-fired power to displace oil-fired capacity. A recent agreement calls for adding a third 500-kilovolt alternating current line to the Pacific Intertie (between Oregon and California) to increase the sale of hydroelectric generation from the Pacific Northwest to displace fossil-fueled generation in California. Many other transmission projects are being planned or built. Nonetheless, adding new transmission capacity is not as simple as building a line between two utilities.³⁴

In the long run, the most important constraint on bulk power transactions will be the availability of surplus generating capacity. The current excess capacity in some regions is one of the factors stimulating interest in increasing bulk power transactions. Over time, demand growth will both use up excess coal-fired and nuclear capacity and create new demands for transactions to displace oil- or gas-fired capacity. By 1995,

³⁴Beyond the technical issues, transmission projects face health and safety concerns, zoning restrictions, right-of-way acquisitions, opposition on esthetic grounds and other complications. "Overview of Electric Power Transmission in North America" (footnote 12) contains examples of key transmission additions that are currently delayed for various reasons.

much of the current surplus capacity will no longer be surplus and the opportunities for bulk power transactions may be significantly reduced.³⁵

Technologies for the 1990's

During the 1970's, the environment within which utilities made investment decisions changed from a relatively predictable continuation of past trends to a much more uncertain and complicated one. Utilities are now concerned about meeting electricity demand in the 1990's without locking themselves into high-cost, risky expansion plans. Utilities are seeking ways to enhance their flexibility in meeting future demand growth. The primary sources of electric power in the 1990's will continue to be large central-station generating plants that use conventional technology. In fact, most of these facilities are already built and in operation. Improvements in the technology of utility-operated generation, transmission, and distribution equipment can be expected to enhance power supplies in the future. Utilities are examining the potential for "fast-start" and modular construction technologies, reducing planning and construction lead times, and providing utilities more flexibility in assessing and meeting demand growth. Also, a variety of less traditional options to supplement these sources is under consideration. These include increased participation by utilities in joint projects, use of new power storage technologies, increased applications of less capital-intensive control mechanisms such as load management and conservation, and growing reliance on nonutility producers such as smaller scale renewable and cogenerator facilities. The technology mix among these options will include old, well-established means, and new, less conventional approaches. By diversifying sources and technologies, such options will reduce risk and exposure while providing enhanced production capability.

While most electricity supplies in the 1990's will be produced by traditional conventional generating plants, owned and operated by electric utilities, many new options may be suited to more diverse applications. The Public Utility Regulatory Policies Act (P.L. 95-617) (PURPA) established the opportunities for markets for electricity produced by cogenerators and small power producers. Cogeneration is the production of electricity and some other form of useful energy (usually heat) from the same energy source. It increases the efficiency with which energy is consumed by producing two outputs from one input. Cogeneration can be effectively used in industrial plants and buildings where energy might be used to produce heat or mechanical drive by using the same energy also to produce electricity. The small-scale production of elec-

tricity using renewable or waste energy sources was classified by the PURPA as small power production. Renewable and waste sources include solar, wind, geothermal, hydropower, and such things as garbage, sewage, and otherwise useless byproducts. These facilities are limited in size to 80 or fewer megawatts. Electric utilities are restricted from owning more than 50 percent of facilities that qualify for market incentives as small power producers and cogenerators. Both cogenerators and small power producers provide opportunities to increase the efficiency of electricity production, to increase the diversity of ownership of productive resources, and to reduce reliance on foreign energy sources.

Energy conservation may be used to reduce the need for electricity. Electricity is valued for the service it performs; wherever the same quantities of service can be obtained using smaller amounts of electricity, there are opportunities to increase consumption without increasing electricity production. In addition to creating the ability to service expanding load by conservation and efficiency improvements, the potential exists to produce more electric power by increasing the amount of electricity consumed during slack hours. Rearranging the hourly pattern of consumption is called load management. Reducing and changing consumption patterns provide a possible source of expanded electricity availability. Rising electricity prices have already provided incentives for improvements in the use of electricity. Technological advances in conservation, electric efficiency, and load management can effectively increase the quantity of electric services available during the 1990's. Investment in these advances can be shared by utilities and consumers.

Electricity supplies in the 1990's will come from a variety of sources. Some large generating stations using the latest technology and the lowest cost available fuel source will be built in regions where large increments of baseload capacity are needed. Substantial quantities of electricity will be produced by cogenerators and small power producers using established technologies. These sources will make the largest contribution to supply in regions with industries well suited to cogeneration or waste utilization, or in places with optimal renewable resource endowments. Conservation efficiency improvements and load management already in place will continue to reduce the amount of electricity required to provide service.

In addition, a number of new technologies are likely to be ready to be used in the 1990's. Table 12 describes known technologies sufficiently developed that commercial deployment could be possible during the next 15 years. Most new technologies pass through several stages of development during which problems in achieving commercial size and economic competitive-

³⁵ECAR/MAAC Coordinating Group, "ECAR/MAAC Interregional Power Transfer Analysis," presentation to the U.S. Department of Energy (June 1985). The study estimates that the average amount of low-cost power in ECAR (including West Virginia, Ohio, Indiana, Kentucky, Michigan, and Western Pennsylvania) available for transfer to other regions will decline from 8,000 megawatts in 1986 to 2,500 megawatts in 1994 for a summer weekday and from 7,500 megawatts to 500 megawatts for a winter weekday.

ness must be worked out. Not all of them will prove themselves during this time. Some may be bypassed by technologies hardly off the drawing board today.

The technologies that may provide additional sources of electricity in the 1990's are not interchangeable. Clearly, the storage technologies are designed for load leveling, that is, they are designed to use less expensive off-peak power to produce additional output in periods of high demand. The renewable sources such as wind and solar power depend on natural events; since power is available from such generators only when the wind blows or the sun shines, these sources are characterized as intermittent to indicate that they may not be available on demand. Most electric generating technologies are designed to operate effectively under specific operating conditions; those that run continuously are designated as serving baseload while those that run only for a few hours at a time are used to meet demand at the peak. A few of the new technologies may blur distinctions in generating characteristics by producing electricity efficiently over a broad range of demand levels that means they can "follow load." The range of potential 1990's technologies includes many of these specialties and can be applied to different problems in electric generation. Those that are commercialized will be the technologies whose characteristics are best suited to the needs of the system.

Some of the technologies shown in Table 12 have depended heavily on special grants or subsidies for their development to date. If these supports are changed, they may not achieve commercialization.

Other technologies in the table have never been demonstrated in the United States; public acceptance of such "unknown" technologies may make them too risky for anyone to finance. However, all of these technologies do share some characteristics. They are amenable to installation in a variety of sizes making them good candidates for diversified ownership. They are designed to avoid environmental problems that plague many conventional generating technologies. They all use renewable or low-cost domestic energy resources.

In fact, the diversity of these technologies probably means that many of them will be viable in some locations. Technological penetration depends not only on the quantity and type of existing generating capacity and electricity demand, but also on the resource endowment of specific locations. At expected efficiency levels, wind, geothermal, and solar resources will be economical to use only at a limited number of locations. Furthermore, technologies aimed at improving system economics by load leveling are useful only if excess lower-cost, baseload generation can be stored to meet peak demand that would otherwise require building new facilities or using high-cost fuels.

The new technologies of the 1990's could provide variety and flexibility. They are likely to be useful in a wide range of sizes, to adapt to resource endowments, to avoid long-run environmental problems, and to fit a number of potential ownership and operating modes. These technologies may have the flexibility and responsiveness that the electric system of the 1990's will require.

Table 12. Nonconventional Technologies for Electricity Generation

Technology	Type	Description	Applications	Deployment
Photovoltaics	Flat plate Concentrator	Semiconductor converts sunlight into direct current electricity.	Many different forms and configurations being tried. Intermittent without storage.	Installed or under construction—20 megawatts. Costs must fall if it is to be commercially competitive.
Solar Thermal	Central receiving Parabolic trough Parabolic dish Solar pond	Converts sunlight into thermal heat which is then used to drive turbine generators.	Utility and nonutility installation; however, there is a minimum size for generation use. Intermittent with some storage.	Installed or under construction—60 megawatts. Operating characteristics must improve if it is to be competitive.
Wind	Small 200 kW Intermediate 200 kW	Converts wind into mechanical energy that can be used to drive turbine generators.	Primarily in groups of small turbines in wind farms. Intermittent without storage.	Installed or under construction—650 megawatts. Must improve efficiency by increasing size in order to be competitive.
Geothermal	Dual-flash Binary cycle	Heat from the core of the earth, where accessible from surface, is used directly or through an exchange medium to power steam turbines.	Experimental designs and installations. Utility and nonutility operated in a variety of sizes. Baseload serving.	Installed or under construction—75 megawatts. Must improve efficiency and reduce water requirements to be competitive.
Fluidized-Bed	Atmospheric	Bed composed of a mass of small particles through which air and combustion gas flow at high velocity causing the particles to behave like fluids.	Widespread boiler applications primarily nonutility, in a variety of sizes. Well suited to cogeneration uses. Baseload serving.	Installed or under construction—865 megawatts. Utility use requires larger scale facilities and resolution of some technical problems.
Coal Gasification	Integrated with combined cycle	Gasifier produces medium Btu gas from coal; gas is burned in turbines; waste heat from gas purification and turbine used in steam drive.	Economies of scale will require relatively large facilities (250 megawatts) likely to be operated by utility or major industrial concern. Primarily base load.	Installed demonstration —100 megawatts.* Requires advances in turbine operating characteristics in order to meet competitive operating costs. May also require Fuel Use Act exemption for backup fuel.
Fuel Cells	Phosphoric acid	Electrochemical reaction between hydrogen and oxygen produces electricity directly.	Potential for a wide variety of installation sizes by utility and nonutility operators. Easy recovery of waste heat ideal for cogeneration technology. Good load following.	Installed demonstration—0.4 megawatts. Operation and maintenance costs and economic life yet to be determined.
Advanced Batteries	Lead acid zinc chloride	Off-peak energy is stored by chemical reaction and drawn down during peak periods to supplement generation.	Load leveling and improved system economics. Large facilities required for economic operation. Utility uses and some dispersed peak dampening uses.	Test installation. Economics of large size must improve to make competitive.
Compressed Air	Salt reservoir Hard rock reservoir Aquifer	Off-peak capacity is used to compress air in a closed chamber, later when required, air is released to boost gas turbine output.	Load leveling technology primarily for utility use. Widespread geological potential.	Single foreign installation. Operation and maintenance cost uncertainties; requires Fuel Use Act exemption.

* An additional installation under construction is omitted because no capacity measure was available.

Source: U.S. Congress, Office of Technology Assessment, **New Electric Power Technologies: Problems and Prospects for the 1990s**, OTA-E-246 (July 1985).

Appendix A

Regional Projections

The following tables present Federal regional projections for U.S. electricity demand, price, capacity, and generation. The first table, A1, identifies the States comprising each of the 10 Federal Regions; Tables A2-A11 contain the regional projections. The projections in these tables are consistent with the national projections summarized in the *Annual Energy Outlook*.

However, regional projections are more uncertain than the national projections because of both a lack of regional data and a lower level of data aggregation for each fuel and sector. These regional projections are intended to be used as indices for interregional comparisons.

Table A1. States Included in the U.S. Federal Regions

Region	States
New England	Maine, New Hampshire, Vermont, Massachusetts, Connecticut, Rhode Island
New York/New Jersey	New York, New Jersey, Puerto Rico, Virgin Islands
Mid-Atlantic	Pennsylvania, Maryland, West Virginia, Virginia, District of Columbia, Delaware
South Atlantic	Kentucky, Tennessee, North Carolina, South Carolina, Mississippi, Alabama, Georgia, Florida
Midwest	Minnesota, Wisconsin, Michigan, Illinois, Indiana, Ohio
Southwest	Texas, New Mexico, Oklahoma, Arkansas, Louisiana
Central	Kansas, Missouri, Iowa, Nebraska
North Central	Montana, North Dakota, South Dakota, Wyoming, Utah, Colorado
West	California, Nevada, Arizona, Hawaii, American Samoa, Guam
Northwest	Washington, Oregon, Idaho, Alaska.

Table A2. New England: Projections for Electric Power, 1985-1995
Selected Values, Various Growth Cases

Growth Case	Middle (Base)			1995			
	1985 ^a	1990	1995	Low Growth	High Growth	High Demand	Reduced Capacity
Electricity Demand (billion kilowatthours)	89.5	100.5	114.8	111.6	118.5	121.8	114.8
Net Capability ^b (million kilowatts)							
Coal Steam	2.3	2.3	2.2	2.2	2.2	2.2	2.2
Other Fossil Steam ^c	9.4	9.3	9.0	9.0	9.0	9.0	9.0
Combined Cycle	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Combustion Turbine	1.3	1.3	2.1	1.5	3.1	4.0	2.1
Nuclear Power	4.2	6.5	6.5	6.5	6.5	6.5	6.5
Hydroelectric/Other ^d	1.5	1.6	1.6	1.6	1.6	1.6	1.6
Pumped Storage Hydroelectric	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Total Capability	20.6	22.9	23.4	22.8	24.4	25.3	23.4
Capability Additions, Cumulative 1985-95 (million kilowatts)							
Planned by Utilities	—	—	2.4	2.4	2.4	2.4	2.4
Additional EIA Estimates	—	—	0.8	0.2	1.8	2.7	0.8
Total Additions	—	—	3.2	2.6	4.2	5.1	3.2
Generation by Fuel Type (billion kilowatthours)							
Coal	15.2	16.7	16.1	16.1	16.4	16.4	16.1
Natural Gas	6.4	2.1	5.0	3.8	4.7	6.2	3.2
Oil	38.7	32.8	36.9	34.6	41.0	43.7	38.7
Nuclear	22.9	35.5	36.3	36.3	36.3	36.3	36.3
All Hydroelectric/Other ^e	4.7	5.3	5.3	5.3	5.3	5.3	5.3
Total Generation	87.9	92.3	99.9	96.4	104.0	107.6	99.9
Price (1985 mills per kilowatthour) ^f							
Capital ^g	30	37	26	26	26	27	26
Fuel ^h	37	35	35	37	34	36	35
Operation and Maintenance ⁱ	22	23	22	23	22	22	21
Total Price	89	95	83	85	83	85	83

^a 1985 is considered a forecast year in this Outlook. Since its preparation, actual 1985 data for many variables have become available and are published in the Energy Information Administration, *Annual Energy Review* (May 1986).

^b Net Capability (Net Summer Capability): The steady hourly output, which generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand or by applying summer derating.

^c Other includes oil, gas, and dual-fired capacity.

^d Includes pondage hydropower and renewable sources such as thermal power, wood, waste, solar energy, and wind.

^e Includes conventional and pumped storage hydroelectric power and other renewable sources such as geothermal power, wood, waste, solar energy, and wind.

^f Prices are model simulations and represent average revenues per kilowatthour of demand over all customer classes.

^g Capital represents the cost to the utility of capital assets needed to provide reliable service. It includes plant depreciation, taxes, and a sufficient return on invested capital to cover interest obligations on outstanding debt and to compensate stockholders.

^h Fuel includes only the direct costs of fuel inputs used to generate electricity required to meet demand.

ⁱ Operation and maintenance (O&M) includes all nonfuel costs necessary to operate and maintain generation, transmission, and distribution capacity used to deliver electricity to end-use sectors.

Note: Totals may not equal sum of parts because of independent rounding.

Sources: Energy Information Administration, Intermediate Future Forecasting System (IFFS). ●Middle (base) case: IFGMMM.D1118851; ●Low growth: IFGMHL.D1118851; ●High growth: IFFMLH.D1118851; ●High demand: IFGMLX.D112851; ●Reduced capacity: IFGMMM.D1118852.

Table A3. New York/New Jersey: Projections for Electric Power, 1985-1995
Selected Values , Various Growth Cases

Growth Case	Middle (Base)			1995			
	1985 ^a	1990	1995	Low Growth	High Growth	High Demand	Reduced Capacity
Electricity Demand (billion kilowatthours)	171.3	189.8	210.5	204.0	217.5	223.7	210.4
Net Capability ^b (million kilowatts)							
Coal Steam	4.7	4.6	4.7	4.7	4.7	4.7	4.7
Other Fossil Steam ^c	17.8	17.5	17.1	17.1	17.1	17.1	17.1
Combined Cycle	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Combustion Turbine	7.1	7.1	6.7	6.7	8.0	9.9	6.7
Nuclear Power	6.5	9.4	9.4	9.4	9.4	9.4	9.4
Hydroelectric/Other ^d	4.1	4.6	4.7	4.7	4.7	4.7	4.7
Pumped Storage Hydroelectric	1.6	2.7	2.7	2.7	2.7	2.7	2.7
Total Capability	42.0	46.3	45.5	45.5	46.8	48.7	45.4
Capability Additions, Cumulative 1985-95 (million kilowatts)							
Planned by Utilities	--	--	4.7	4.7	4.7	4.7	4.6
Additional EIA Estimates	--	--	0	0	1.3	3.2	0
Total Additions	--	--	4.7	4.7	6.0	7.9	4.6
Generation by Fuel Type (billion kilowatthours)							
Coal	26.7	27.3	27.8	27.8	27.8	27.8	27.8
Natural Gas	17.9	13.8	23.2	19.1	28.4	30.5	14.1
Oil	41.6	33.1	56.3	53.3	58.3	62.7	65.7
Nuclear	35.2	51.3	52.5	52.5	52.5	52.5	52.5
All Hydroelectric/Other ^e	20.2	23.2	25.5	25.5	25.5	25.5	25.2
Total Generation	141.3	148.9	185.2	178.2	192.6	199.0	185.2
Price (1985 mills per kilowatthour) ^f							
Capital ^g	40	42	32	31	32	32	32
Fuel ^h	34	33	40	42	39	40	40
Operation and Maintenance ⁱ	19	19	19	19	18	18	18
Total Price	93	94	90	92	89	91	91

^a 1985 is considered a forecast year in this Outlook. Since its preparation, actual 1985 data for many variables have become available and are published in the Energy Information Administration, *Annual Energy Review* (May 1986).

^b Net Capability (Net Summer Capability): The steady hourly output, which generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand or by applying summer derating.

^c Other includes oil, gas, and dual-fired capacity.

^d Includes pondage hydropower and renewable sources such as thermal power, wood, waste, solar energy, and wind.

^e Includes conventional and pumped storage hydroelectric power and other renewable sources such as geothermal power, wood, waste, solar energy, and wind.

^f Prices are model simulations and represent average revenues per kilowatthour of demand over all customer classes.

^g Capital represents the cost to the utility of capital assets needed to provide reliable service. It includes plant depreciation, taxes, and a sufficient return on invested capital to cover interest obligations on outstanding debt and to compensate stockholders.

^h Fuel includes only the direct costs of fuel inputs used to generate electricity required to meet demand.

ⁱ Operation and maintenance (O&M) includes all nonfuel costs necessary to operate and maintain generation, transmission, and distribution capacity used to deliver electricity to end-use sectors.

Note: Totals may not equal sum of parts because of independent rounding.

Sources: Energy Information Administration, Intermediate Future Forecasting System (IFFS). •Middle (base) case: IFGMMM.D1118851; •Low growth: IFGMHL.D1118851; •High growth: IFFMLH.D1118851; •High demand: IFGMLX.D112851; •Reduced capacity: IFGMMM.D1118852.

Table A4. Mid-Atlantic: Projections for Electric Power, 1985-1995
Selected Values, Various Growth Cases

Growth Case	Middle (Base)			1995			
	1985 ^a	1990	1995	Low Growth	High Growth	High Demand	Reduced Capacity
Electricity Demand (billion kilowatthours)	237.3	268.9	302.1	295.6	308.9	316.5	302.5
Net Capability ^b (million kilowatts)							
Coal Steam	38.7	38.7	40.0	40.0	40.0	40.0	39.3
Other Fossil Steam ^c	9.1	8.3	7.6	7.6	7.6	7.6	7.6
Combined Cycle	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Combustion Turbine	3.6	4.1	11.7	10.4	13.4	15.3	13.3
Nuclear Power	11.8	12.6	13.7	13.7	13.7	13.7	12.6
Hydroelectric/Other ^d	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Pumped Storage Hydroelectric	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Total Capability	68.9	69.5	78.6	77.3	80.3	82.2	78.5
Capability Additions, Cumulative 1985-95 (million kilowatts)							
Planned by Utilities	--	--	6.5	6.5	6.5	6.5	4.8
Additional EIA Estimates	--	--	8.3	7.0	10.0	11.9	9.8
Total Additions	--	--	14.8	13.4	16.5	18.4	14.6
Generation by Fuel Type (billion kilowatthours)							
Coal	218.1	229.5	238.0	237.4	238.6	238.6	235.3
Natural Gas	1.5	5.6	22.0	18.2	27.3	32.5	28.1
Oil	10.3	28.1	31.4	28.4	33.1	36.0	34.3
Nuclear	58.3	68.6	76.2	76.2	76.2	76.2	70.3
All Hydroelectric/Other ^e	3.2	0.9	0.9	0.9	0.9	1.2	0.9
Total Generation	291.0	332.9	368.4	361.4	376.0	384.2	369.0
Price (1985 mills per kilowatthour) ^f							
Capital ^g	28	25	22	22	22	22	21
Fuel ^h	20	23	26	26	26	28	28
Operation and Maintenance ⁱ	18	17	16	17	16	16	16
Total Price	65	65	65	65	64	66	65

^a 1985 is considered a forecast year in this Outlook. Since its preparation, actual 1985 data for many variables have become available and are published in the Energy Information Administration, **Annual Energy Review** (May 1986).

^b Net Capability (Net Summer Capability): The steady hourly output, which generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand or by applying summer derating.

^c Other includes oil, gas, and dual-fired capacity.

^d Includes pondage hydropower and renewable sources such as thermal power, wood, waste, solar energy, and wind.

^e Includes conventional and pumped storage hydroelectric power and other renewable sources such as geothermal power, wood, waste, solar energy, and wind.

^f Prices are model simulations and represent average revenues per kilowatthour of demand over all customer classes.

^g Capital represents the cost to the utility of capital assets needed to provide reliable service. It includes plant depreciation, taxes, and a sufficient return on invested capital to cover interest obligations on outstanding debt and to compensate stockholders.

^h Fuel includes only the direct costs of fuel inputs used to generate electricity required to meet demand.

ⁱ Operation and maintenance (O&M) includes all nonfuel costs necessary to operate and maintain generation, transmission, and distribution capacity used to deliver electricity to end-use sectors.

Note: Totals may not equal sum of parts because of independent rounding.

Sources: Energy Information Administration, Intermediate Future Forecasting System (IFFS). ●Middle (base) case: IFGMMM.D1118851; ●Low growth: IFGMHL.D1118851; ●High growth: IFFMLH.D1118851; ●High demand: IFGMLX.D1118851; ●Reduced capacity: IFGMMM.D1118852.

**Table A5. South Atlantic: Projections for Electric Power, 1985-1995
Selected Values, Various Growth Cases**

Growth Case	Middle (Base)			1995			
	1985 ^a	1990	1995	Low Growth	High Growth	High Demand	Reduced Capacity
Electricity Demand (billion kilowatthours)	474.7	549.4	633.7	623.2	645.1	660.9	635.9
Net Capability ^b (million kilowatts)							
Coal Steam	71.4	75.5	81.3	81.3	81.3	81.3	77.3
Other Fossil Steam ^c	17.9	17.3	16.5	16.5	16.5	16.5	16.5
Combined Cycle	0.6	0.7	0.8	0.8	0.8	0.8	0.8
Combustion Turbine	9.7	9.5	9.2	9.2	9.2	9.3	9.2
Nuclear Power	22.9	29.6	30.8	30.8	30.8	30.8	29.6
Hydroelectric/Other ^d	11.4	11.5	11.6	11.6	11.6	11.6	11.6
Pumped Storage Hydroelectric	3.1	3.4	4.3	4.3	4.3	4.3	4.3
Total Capability	137.0	147.5	154.5	154.5	154.5	154.6	149.3
Capability Additions, Cumulative 1985-95 (million kilowatts)							
Planned by Utilities	—	—	23.2	23.2	23.2	23.2	17.9
Additional EIA Estimates	—	—	0	0	0	0.1	0
Total Additions	—	—	23.2	23.2	23.2	23.3	17.9
Generation by Fuel Type (billion kilowatthours)							
Coal	353.2	405.3	465.1	459.3	470.4	476.8	456.6
Natural Gas	4.7	3.5	11.4	14.4	1.8	5.0	5.9
Oil	1.8	1.8	14.9	6.4	31.7	39.0	35.5
Nuclear	118.4	157.4	168.8	168.8	168.8	168.8	164.7
All Hydroelectric/Other ^e	31.7	35.8	35.5	35.5	35.5	35.5	35.5
Total Generation	509.7	603.8	695.8	684.3	708.1	725.1	698.1
Price (1985 mills per kilowatthour) ^f							
Capital ^g	27	27	18	18	18	18	17
Fuel ^h	17	17	19	19	19	20	20
Operation and Maintenance ⁱ	16	16	15	15	15	15	15
Total Price	60	59	53	52	53	53	52

^a 1985 is considered a forecast year in this Outlook. Since its preparation, actual 1985 data for many variables have become available and are published in the Energy Information Administration, *Annual Energy Review* (May 1986).

^b Net Capability (Net Summer Capability): The steady hourly output, which generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand or by applying summer derating.

^c Other includes oil, gas, and dual-fired capacity.

^d Includes pondage hydropower and renewable sources such as thermal power, wood, waste, solar energy, and wind.

^e Includes conventional and pumped storage hydroelectric power and other renewable sources such as geothermal power, wood, waste, solar energy, and wind.

^f Prices are model simulations and represent average revenues per kilowatthour of demand over all customer classes.

^g Capital represents the cost to the utility of capital assets needed to provide reliable service. It includes plant depreciation, taxes, and a sufficient return on invested capital to cover interest obligations on outstanding debt and to compensate stockholders.

^h Fuel includes only the direct costs of fuel inputs used to generate electricity required to meet demand.

ⁱ Operation and maintenance (O&M) includes all nonfuel costs necessary to operate and maintain generation, transmission, and distribution capacity used to deliver electricity to end-use sectors.

Note: Totals may not equal sum of parts because of independent rounding.

Sources: Energy Information Administration, Intermediate Future Forecasting System (IFFS). •Middle (base) case: IFGMMM.D1118851; •Low growth: IFGMHL.D1118851; •High growth: IFFMLH.D1118851; •High demand: IFGLMX.D112851; •Reduced capacity: IFGMMM.D1118852.

Table A6. Midwest: Projections for Electric Power, 1985-1995
Selected Values, Various Growth Cases

Growth Case	Middle (Base)			1995			
	1985 ^a	1990	1995	Low Growth	High Growth	High Demand	Reduced Capacity
Electricity Demand (billion kilowatthours)	441.5	486.4	550.2	537.2	563.6	582.0	554.7
Net Capability ^b (million kilowatts)							
Coal Steam	79.3	82.2	83.0	83.0	83.0	83.0	82.9
Other Fossil Steam ^c	7.1	7.0	7.0	7.0	7.0	7.0	7.0
Combined Cycle	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Combustion Turbine	7.2	7.2	7.3	7.3	7.3	10.4	7.3
Nuclear Power	16.3	21.8	23.8	23.8	23.8	23.8	21.8
Hydroelectric/Other ^d	1.4	1.5	1.5	1.5	1.5	1.5	1.5
Pumped Storage Hydroelectric	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Total Capability	113.3	121.7	124.6	124.6	124.6	127.6	122.4
Capability Additions, Cumulative 1985-95 (million kilowatts)							
Planned by Utilities	—	—	16.1	16.1	16.1	16.1	13.9
Additional EIA Estimates	—	—	0	0	0	3.1	0
Total Additions	—	—	16.1	16.1	16.1	19.2	13.9
Generation by Fuel Type (billion kilowatthours)							
Coal	365.2	384.2	427.9	417.1	438.2	450.8	437.3
Natural Gas	1.8	1.8	3.8	2.9	2.6	2.6	5.0
Oil	1.5	1.2	7.0	4.4	12.0	20.2	9.4
Nuclear	80.0	118.1	129.1	129.5	129.5	129.5	121.0
All Hydroelectric/Other ^e	5.6	7.0	7.0	7.0	7.0	7.0	6.7
Total Generation	454.0	512.3	575.0	561.0	589.7	610.2	579.7
Price (1985 mills per kilowatthour) ^f							
Capital ^g	29	30	22	22	22	22	20
Fuel ^h	19	19	20	20	20	21	21
Operation and Maintenance ⁱ	17	18	17	17	17	17	16
Total Price	66	67	59	59	59	60	57

^a 1985 is considered a forecast year in this Outlook. Since its preparation, actual 1985 data for many variables have become available and are published in the Energy Information Administration, **Annual Energy Review** (May 1986).

^b Net Capability (Net Summer Capability): The steady hourly output, which generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand or by applying summer derating.

^c Other includes oil, gas, and dual-fired capacity.

^d Includes pondage hydropower and renewable sources such as thermal power, wood, waste, solar energy, and wind.

^e Includes conventional and pumped storage hydroelectric power and other renewable sources such as geothermal power, wood, waste, solar energy, and wind.

^f Prices are model simulations and represent average revenues per kilowatthour of demand over all customer classes.

^g Capital represents the cost to the utility of capital assets needed to provide reliable service. It includes plant depreciation, taxes, and a sufficient return on invested capital to cover interest obligations on outstanding debt and to compensate stockholders.

^h Fuel includes only the direct costs of fuel inputs used to generate electricity required to meet demand.

ⁱ Operation and maintenance (O&M) includes all nonfuel costs necessary to operate and maintain generation, transmission, and distribution capacity used to deliver electricity to end-use sectors.

Note: Totals may not equal sum of parts because of independent rounding.

Sources: Energy Information Administration, Intermediate Future Forecasting System (IFFS). •Middle (base) case: IFGMMM.D1118851; •Low growth: IFGMLH.D1118851; •High growth: IFFMLH.D1118851; •High demand: IFGMLX.D112851; •Reduced capacity: IFGMMM.D1118852.

Table A7. Southwest: Projections for Electric Power, 1985-1995
Selected Values, Various Growth Cases

Growth Case	Middle (Base)			1995			
	1985 ^a	1990	1995	Low Growth	High Growth	High Demand	Reduced Capacity
Electricity Demand (billion kilowatthours)	342.2	394.6	452.0	443.4	460.5	470.7	451.4
Net Capability ^b (million kilowatts)							
Coal Steam	31.2	35.6	46.9	46.9	46.9	46.9	37.1
Other Fossil Steam ^c	55.3	53.8	50.4	50.4	50.4	50.4	50.4
Combined Cycle	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Combustion Turbine	2.4	3.4	3.5	3.5	3.6	6.1	9.4
Nuclear Power	2.8	8.5	8.5	8.5	8.5	8.5	8.5
Hydroelectric/Other ^d	2.9	3.0	3.0	3.0	3.0	3.0	3.0
Pumped Storage Hydroelectric	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total Capability	96.0	105.6	113.7	113.7	113.7	116.3	109.8
Capability Additions, Cumulative 1985-95 (million kilowatts)							
Planned by Utilities	--	--	25.7	25.7	25.7	25.7	16.0
Additional EIA Estimates	--	--	0	0	0	2.6	5.8
Total Additions	--	--	25.7	25.7	25.7	28.3	26.9
Generation by Fuel Type (billion kilowatthours)							
Coal	183.8	215.4	280.8	280.8	280.8	280.8	228.3
Natural Gas	177.3	165.9	157.7	150.1	161.8	163.0	210.4
Oil	0	0	1.2	0	5.9	15.5	0
Nuclear	12.9	44.3	46.9	46.9	46.9	46.9	46.9
All Hydroelectric/Other ^e	5.9	6.7	6.7	6.7	6.7	6.7	6.4
Total Generation	379.8	432.3	493.3	484.5	501.8	512.9	492.4
Price (1985 mills per kilowatthour) ^f							
Capital ^g	23	27	22	21	22	23	20
Fuel ^h	30	28	30	30	31	32	36
Operation and Maintenance ⁱ	13	13	13	13	13	13	13
Total Price	66	68	65	64	66	68	68

^a 1985 is considered a forecast year in this Outlook. Since its preparation, actual 1985 data for many variables have become available and are published in the Energy Information Administration, *Annual Energy Review* (May 1986).

^b Net Capability (Net Summer Capability): The steady hourly output, which generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand or by applying summer derating.

^c Other includes oil, gas, and dual-fired capacity.

^d Includes pondage hydropower and renewable sources such as thermal power, wood, waste, solar energy, and wind.

^e Includes conventional and pumped storage hydroelectric power and other renewable sources such as geothermal power, wood, waste, solar energy, and wind.

^f Prices are model simulations and represent average revenues per kilowatthour of demand over all customer classes.

^g Capital represents the cost to the utility of capital assets needed to provide reliable service. It includes plant depreciation, taxes, and a sufficient return on invested capital to cover interest obligations on outstanding debt and to compensate stockholders.

^h Fuel includes only the direct costs of fuel inputs used to generate electricity required to meet demand.

ⁱ Operation and maintenance (O&M) includes all nonfuel costs necessary to operate and maintain generation, transmission, and distribution capacity used to deliver electricity to end-use sectors.

Note: Totals may not equal sum of parts because of independent rounding.

Sources: Energy Information Administration, Intermediate Future Forecasting System (IFFS). ●Middle (base) case: IFGMMM.D1118851; ●Low growth: IFGMHL.D1118851; ●High growth: IFFMLH.D1118851; ●High demand: IFGMLX.D112851; ●Reduced capacity: IFGMMM.D1118852.

**Table A8. Central: Projections for Electric Power, 1985-1995
Selected Values, Various Growth Cases**

Growth Case	Middle (Base)			1995			
	1985 ^a	1990	1995	Low Growth	High Growth	High Demand	Reduced Capacity
Electricity Demand (billion kilowatthours)	116.2	130.4	146.3	143.0	149.7	154.3	147.2
Net Capability ^b (million kilowatts)							
Coal Steam	25.0	25.0	26.2	26.2	26.2	26.2	25.0
Other Fossil Steam ^c	2.7	2.6	2.6	2.6	2.6	2.6	2.6
Combined Cycle	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Combustion Turbine	4.9	5.1	7.1	6.2	8.2	9.4	8.3
Nuclear Power	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Hydroelectric/Other ^d	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Pumped Storage Hydroelectric	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Total Capability	38.3	38.4	41.7	40.8	42.8	44.0	41.6
Capability Additions, Cumulative 1985-95 (million kilowatts)							
Planned by Utilities	—	—	2.8	2.8	2.8	2.8	1.6
Additional EIA Estimates	—	—	1.9	1.0	3.1	4.3	3.1
Total Additions	—	—	4.7	3.8	5.9	7.1	4.8
Generation by Fuel Type (billion kilowatthours)							
Coal	107.3	119.3	131.3	128.7	133.6	136.3	129.2
Natural Gas	0.6	2.1	4.7	3.5	6.2	8.5	7.6
Oil	0.3	0.3	0.3	0.3	0.6	0.3	0.6
Nuclear	16.7	21.7	22.3	22.3	22.3	22.3	22.3
All Hydroelectric/Other ^e	3.2	3.5	3.5	3.5	3.5	3.5	3.5
Total Generation	128.1	147.1	162.1	158.3	165.9	171.2	163.0
Price (1985 mills per kilowatthour) ^f							
Capital ^g	33	26	21	21	21	20	20
Fuel ^h	18	18	19	19	20	21	20
Operation and Maintenance ⁱ	20	19	18	19	18	18	18
Total Price	71	63	59	58	59	59	58

^a 1985 is considered a forecast year in this Outlook. Since its preparation, actual 1985 data for many variables have become available and are published in the Energy Information Administration, *Annual Energy Review* (May 1986).

^b Net Capability (Net Summer Capability): The steady hourly output, which generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand or by applying summer derating.

^c Other includes oil, gas, and dual-fired capacity.

^d Includes pondage hydropower and renewable sources such as thermal power, wood, waste, solar energy, and wind.

^e Includes conventional and pumped storage hydroelectric power and other renewable sources such as geothermal power, wood, waste, solar energy, and wind.

^f Prices are model simulations and represent average revenues per kilowatthour of demand over all customer classes.

^g Capital represents the cost to the utility of capital assets needed to provide reliable service. It includes plant depreciation, taxes, and a sufficient return on invested capital to cover interest obligations on outstanding debt and to compensate stockholders.

^h Fuel includes only the direct costs of fuel inputs used to generate electricity required to meet demand.

ⁱ Operation and maintenance (O&M) includes all nonfuel costs necessary to operate and maintain generation, transmission, and distribution capacity used to deliver electricity to end-use sectors.

Note: Totals may not equal sum of parts because of independent rounding.

Sources: Energy Information Administration, Intermediate Future Forecasting System (IFFS). •Middle (base) case: IFGMMM.D1118851; •Low growth: IFGMHL.D1118851; •High growth: IFFMLH.D1118851; •High demand: IFGMLX.D112851; •Reduced capacity: IFGMMM.D1118852.

Table A9. North Central: Projections for Electric Power, 1985-1995
Selected Values, Various Growth Cases

Growth Case	Middle (Base)			1995			
	1985 ^a	1990	1995	Low Growth	High Growth	High Demand	Reduced Capacity
Electricity Demand (billion kilowatthours)	70.5	84.1	97.8	96.0	99.9	102.3	97.9
Net Capability ^b (million kilowatts)							
Coal Steam	18.6	21.2	22.5	22.5	22.5	22.5	21.2
Other Fossil Steam ^c	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Combined Cycle	0	0	0	0	0	0	0
Combustion Turbine	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Nuclear Power	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Hydroelectric/Other ^d	5.1	5.1	5.1	5.1	5.1	5.1	5.1
Pumped Storage Hydroelectric	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total Capability	26.0	28.7	29.9	29.9	29.9	29.9	28.7
Capability Additions, Cumulative 1985-95 (million kilowatts)							
Planned by Utilities	--	--	4.3	4.3	4.3	4.3	3.1
Additional EIA Estimates	--	--	0	0	0	0	0
Total Additions	--	--	4.3	4.3	4.3	4.3	3.1
Generation by Fuel Type (billion kilowatthours)							
Coal	84.7	119.6	133.1	132.2	133.9	134.2	129.2
Natural Gas	0	0.3	2.3	1.5	3.2	4.4	4.7
Oil	0	0.3	0.3	1.5	0.6	1.5	4.7
Nuclear	0.6	0.6	0.6	0.6	0.6	0.6	0.6
All Hydroelectric/Other ^e	19.6	21.7	21.4	21.4	21.4	21.4	21.4
Total Generation	104.9	142.1	157.4	155.6	159.7	162.4	157.7
Price (1985 mills per kilowatthour) ^f							
Capital ^g	28	23	18	18	18	19	17
Fuel ^h	12	14	16	15	17	18	19
Operation and Maintenance ⁱ	21	21	19	20	19	19	19
Total Price	61	58	53	53	54	56	55

^a 1985 is considered a forecast year in this Outlook. Since its preparation, actual 1985 data for many variables have become available and are published in the Energy Information Administration, *Annual Energy Review* (May 1986).

^b Net Capability (Net Summer Capability): The steady hourly output, which generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand or by applying summer derating.

^c Other includes oil, gas, and dual-fired capacity.

^d Includes pondage hydropower and renewable sources such as thermal power, wood, waste, solar energy, and wind.

^e Includes conventional and pumped storage hydroelectric power and other renewable sources such as geothermal power, wood, waste, solar energy, and wind.

^f Prices are model simulations and represent average revenues per kilowatthour of demand over all customer classes.

^g Capital represents the cost to the utility of capital assets needed to provide reliable service. It includes plant depreciation, taxes, and a sufficient return on invested capital to cover interest obligations on outstanding debt and to compensate stockholders.

^h Fuel includes only the direct costs of fuel inputs used to generate electricity required to meet demand.

ⁱ Operation and maintenance (O&M) includes all nonfuel costs necessary to operate and maintain generation, transmission, and distribution capacity used to deliver electricity to end-use sectors.

Note: Totals may not equal sum of parts because of independent rounding.

Sources: Energy Information Administration, Intermediate Future Forecasting System (IFFS). •Middle (base) case: IFGMMM.D1118851; •Low growth: IFGMHL.D1118851; •High growth: IFFMLH.D1118851; •High demand: IFGMLX.D112851; •Reduced capacity: IFGMMM.D1118852.

Table A10. West: Projections for Electric Power, 1985-1995
Selected Values, Various Growth Cases

Growth Case	Middle (Base)			1995			
	1985 ^a	1990	1995	Low Growth	High Growth	High Demand	Reduced Capacity
Electricity Demand (billion kilowatthours)	229.9	275.1	318.3	312.1	326.2	333.8	318.9
Net Capability ^b (million kilowatts)							
Coal Steam	7.3	7.6	10.2	10.2	10.2	10.2	8.0
Other Fossil Steam ^c	25.2	24.7	24.6	24.6	24.6	24.6	24.6
Combined Cycle	1.4	1.5	1.5	1.5	1.5	1.5	1.5
Combustion Turbine	4.0	4.1	10.3	8.7	12.3	14.3	12.7
Nuclear Power	6.9	9.4	9.4	9.4	9.4	9.4	9.4
Hydroelectric/Other ^d	13.1	14.5	15.0	15.0	15.0	15.0	15.0
Pumped Storage Hydroelectric	3.3	3.5	3.7	3.7	3.7	3.7	3.6
Total Capability	61.1	65.3	74.5	72.9	76.6	78.5	74.7
Capability Additions, Cumulative 1985-95 (million kilowatts)							
Planned by Utilities	--	--	11.3	11.3	11.3	11.3	9.1
Additional EIA Estimates	--	--	6.1	4.5	8.2	10.1	8.5
Total Additions	--	--	17.4	15.8	19.5	21.4	17.6
Generation by Fuel Type (billion kilowatthours)							
Coal	42.2	45.7	61.8	61.8	61.8	61.8	48.1
Natural Gas	82.4	88.8	107.3	103.5	55.7	60.1	83.2
Oil	4.7	2.3	8.2	5.3	67.7	71.2	46.6
Nuclear	24.9	51.0	52.2	52.2	52.2	52.2	52.2
All Hydroelectric/Other ^e	54.2	65.9	69.5	69.5	69.5	69.8	69.5
Total Generation	208.7	254.1	299.0	292.5	307.2	315.1	299.5
Price (1985 mills per kilowatthour) ^f							
Capital ^g	29	25	19	19	20	20	19
Fuel ^h	27	24	32	31	32	33	34
Operation and Maintenance ⁱ	15	16	15	15	15	15	15
Total Price	71	65	66	65	66	68	68

^a 1985 is considered a forecast year in this Outlook. Since its preparation, actual 1985 data for many variables have become available and are published in the Energy Information Administration, *Annual Energy Review* (May 1986).

^b Net Capability (Net Summer Capability): The steady hourly output, which generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand or by applying summer derating.

^c Other includes oil, gas, and dual-fired capacity.

^d Includes pondage hydropower and renewable sources such as thermal power, wood, waste, solar energy, and wind.

^e Includes conventional and pumped storage hydroelectric power and other renewable sources such as geothermal power, wood, waste, solar energy, and wind.

^f Prices are model simulations and represent average revenues per kilowatthour of demand over all customer classes.

^g Capital represents the cost to the utility of capital assets needed to provide reliable service. It includes plant depreciation, taxes, and a sufficient return on invested capital to cover interest obligations on outstanding debt and to compensate stockholders.

^h Fuel includes only the direct costs of fuel inputs used to generate electricity required to meet demand.

ⁱ Operation and maintenance (O&M) includes all nonfuel costs necessary to operate and maintain generation, transmission, and distribution capacity used to deliver electricity to end-use sectors.

Note: Totals may not equal sum of parts because of independent rounding.

Sources: Energy Information Administration, Intermediate Future Forecasting System (IFFS). •Middle (base) case: IFGMMM.D1118851; •Low growth: IFGMHL.D1118851; •High growth: IFFMLH.D1118851; •High demand: IFGMLX.D112851; •Reduced capacity: IFGMMM.D1118852.

**Table A11. Northwest: Projections for Electric Power, 1985-1995
Selected Values, Various Growth Cases**

Growth Case	Middle (Base)			1995			
	1985 ^a	1990	1995	Low Growth	High Growth	High Demand	Reduced Capacity
Electricity Demand (billion kilowatthours)	144.0	171.7	200.5	198.1	203.6	207.5	201.6
Net Capability ^b (million kilowatts)							
Coal Steam	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Other Fossil Steam ^c	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Combined Cycle	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Combustion Turbine	1.9	2.0	2.1	2.0	2.9	4.0	3.8
Nuclear Power	3.0	3.0	4.3	4.3	4.3	4.3	3.0
Hydroelectric/Other ^d	31.2	31.6	31.6	31.6	31.6	31.6	31.6
Pumped Storage Hydroelectric	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total Capability	38.7	39.1	40.4	40.3	41.2	42.3	40.9
Capability Additions, Cumulative 1985-95 (million kilowatts)							
Planned by Utilities	--	--	1.9	1.9	1.9	1.9	0.7
Additional EIA Estimates	--	--	0.1	0	0.9	2.1	1.8
Total Additions	--	--	2.0	1.9	2.8	4.0	2.5
Generation by Fuel Type (billion kilowatthours)							
Coal	2.6	5.6	8.2	7.9	8.2	9.4	9.1
Natural Gas	0	0.9	2.9	5.6	2.9	2.6	3.8
Oil	0	0.6	5.0	0.6	7.9	11.7	9.4
Nuclear	13.2	13.8	20.2	20.2	20.2	20.2	15.2
All Hydroelectric/Other ^e	135.4	152.1	152.1	152.1	152.1	152.1	152.1
Total Generation	151.5	172.9	188.5	188.5	191.4	196.1	189.3
Price (1985 mills per kilowatthour) ^f							
Capital ^g	18	15	10	10	11	11	8
Fuel ^h	4	6	8	7	8	10	10
Operation and Maintenance ⁱ	11	11	10	11	11	11	10
Total Price	33	31	29	28	30	32	28

^a 1985 is considered a forecast year in this Outlook. Since its preparation, actual 1985 data for many variables have become available and are published in the Energy Information Administration, Annual Energy Review (May 1986).

^b Net Capability (Net Summer Capability): The steady hourly output, which generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand or by applying summer derating.

^c Other includes oil, gas, and dual-fired capacity.

^d Includes pondage hydropower and renewable sources such as thermal power, wood, waste, solar energy, and wind.

^e Includes conventional and pumped storage hydroelectric power and other renewable sources such as geothermal power, wood, waste, solar energy, and wind.

^f Prices are model simulations and represent average revenues per kilowatthour of demand over all customer classes.

^g Capital represents the cost to the utility of capital assets needed to provide reliable service. It includes plant depreciation, taxes, and a sufficient return on invested capital to cover interest obligations on outstanding debt and to compensate stockholders.

^h Fuel includes only the direct costs of fuel inputs used to generate electricity required to meet demand.

ⁱ Operation and maintenance (O&M) includes all nonfuel costs necessary to operate and maintain generation, transmission, and distribution capacity used to deliver electricity to end-use sectors.

Note: Totals may not equal sum of parts because of independent rounding.

Sources: Energy Information Administration, Intermediate Future Forecasting System (IFFS). •Middle (base) case: IFGMMM.D1118851; •Low growth: IFGMHL.D1118851; •High growth: IFFMLH.D1118851; •High demand: IFGMLX.D112851; •Reduced capacity: IFGMMM.D1118852.

Appendix B

Methodology and Assumptions

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Methodology and Assumptions

Electric Utility Methodology

The forecasts presented in this *Annual Outlook for U.S. Electric Power* result from the interaction among model representations of the key energy supply, conversion, and consumption sectors. The forecasts represent solutions to the integrating framework of the Intermediate Future Forecasting System (IFFS),³⁶ which provides an internally consistent set of prices and quantities for which energy supplies equal consumption on an annual basis. The IFFS accommodates the major economic factors affecting energy supply and demand, including interfuel competition and Government policies and regulations. The IFFS consists of a central integrating procedure, together with individual modules for electric utilities, oil refining, natural gas supply, coal supply, and energy demand by end-use sector.

The assumptions underlying the representations reflect recently published values for historical data, empirically estimated relationships observed over recent history, and plausible paths for future behavior. The baseline assumptions about the behavior of the domestic economy are based on values for Gross National Product and other macroeconomic variables forecast by Data Resources, Inc.³⁷

Electricity Market Module

Electric utilities are treated as regulated regional monopolies that attempt to minimize cost. The Electricity Market Module³⁸ estimates capacity expansion and simulates regulatory behavior in pricing electricity as a function of operating and capital costs. The electric utility industry uses a variety of plant types and fuel inputs: coal-, gas-, or oil-fired steam; gas or oil combined cycle; gas or oil turbines; and nuclear and hydroelectric energy. The utilization of generating capacity is forecast to depend on relative generation costs, reli-

ability, and demand, while capacity expansion is a function of total annualized system cost. Under the current regulatory structure, the supply price is based on the average cost of generation, composed of fuel and operation and maintenance costs. Capital cost includes a capital charge on the undepreciated portion of existing plants and a capital charge for construction work in progress, where allowed.

National Utility Financial Statement Model (NUFS)

For financial projections, EIA also uses the National Utility Financial Statement Model (NUFS). The NUFS is a financial accounting model consisting of a set of equations describing the regulatory/financial environment of the electric utility industry. NUFS is designed to forecast financial information on an annual basis for electric utilities. It is used to produce results at the national and regional electric utility level of aggregation. The inputs to the model include forecast capacity expansion plans, operating costs, regulatory environment, and financial data. The outputs from the model include forecasts of income statements, balance sheets, sources and uses of funds, revenue requirements, electricity prices, and other financial ratios.

Electric Utility Assumptions

Capacity Factors

The utilization rates for existing nuclear and fossil-fired steam plants are based on actual data through 1984. In the projection period, plants experiencing historical

³⁶Energy Information Administration, *Intermediate Future Forecasting System: Executive Summary*, DOE/EIA-0430 (Washington, DC, 1983).

³⁷This Outlook is based on a modified version of the Data Resources, Inc. U.S. economic forecast TREND25YER0985. The underlying forecast is described in Data Resources, Inc., *U.S. Long-Term Review* (Lexington, Massachusetts, Fall 1985).

³⁸Energy Information Administration, *Model Documentation: Electricity Market Module*, DOE/EIA-M001 (Washington, DC, 1984).

Table B1. Capacity Factors for Nuclear Plants
(Percent)

DOE Region	1985 ^a	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
1-7, 9	59	61	61	61	62	62	62	63	63	63	63
8	29	31	33	34	36	38	40	42	44	46	48
10	47	48	49	50	51	52	53	54	55	56	57

^a 1985 is considered a forecast year. Since 1985 data were not available at the time of the analysis, assumptions were made for 1985 consistent with other years in the forecast period.

Source: Energy Information Administration, Electric Power Division.

utilization rates above 68 percent are assumed to maintain current rates as maximum potential. The potential utilization rates for all other existing coal-fired plants are assumed to grow to 68 percent in 1986 and to remain constant. Table B1 provides the equilibrium cycle factors for nuclear plants. New nuclear plants are assumed to operate at a 44-percent capacity factor during the first fuel cycle (typically the first 2 years of operation) and at the equilibrium cycle capacity factor thereafter.

Nuclear Fuel

It is assumed that adequate supplies of uranium will exist throughout the forecast period and that the cost, in constant 1985 dollars, will decline from \$0.75 per million Btu in 1984 to \$0.54 per million Btu in 1995.

Plant Efficiencies

In each forecast year, the plant efficiencies for existing plants are assumed to be the average of the actual figures for 1982 through 1984. The efficiencies for new plants are given in Table B2. Estimates for coal-fired plants were derived from EIA's *Regionalized Capital and Operation and Maintenance Cost Estimates for Emission Control Equipment for New Coal-fired Power Plants*, May 1982. Note that environmental regulations require that any new coal plant that does not have a flue gas desulfurization (FGD) system must use low-sulfur coal. Nuclear and hydroelectric efficiencies are obtained from EIA's December 1983 *Monthly Energy Review*. All other efficiencies were taken from DOE's *Data Notebook Generating Technology Assessment*, R-035-DOE-80, January 1980.

Table B2. Plant Efficiencies for New Generating Units
(Percent)

Plant Type	Plant Efficiencies ^a
Noncoal Fossil-Fired Steam	35
Coal-Fired without	
Flue Gas Desulfurization	
Bituminous--Low Sulfur	37
Subbituminous--Low Sulfur	36
Lignite--Low Sulfur	35
Coal-Fired with	
Flue Gas Desulfurization	
Bituminous--All Fuel Levels	35
Subbituminous--Low Sulfur	34
Subbituminous--Medium Sulfur	33
Lignite--Low Sulfur	33
Lignite--Medium Sulfur	34
Combined Cycle	36
Combustion Turbine	24
Nuclear Power	31
Hydroelectric Power	33

^a Plant efficiency is defined as the ratio of output electrical energy to input fuel energy, expressed as a percentage.

Appendix A

Regional Projections

Environmental Standards

Existing coal-fired plants are assumed to burn the same coal types as they did in 1984, which implies that the plants will meet or exceed (emit less than) State Implementation Plan (SIP) standards. Coal-fired plants currently under construction that were licensed before September 1978 must satisfy the New Source Performance Standards (NSPS). If the license for a new coal-fired plant was obtained after September 1978, the plant must satisfy the Revised New Source Performance Standards (RNSPS).

Plant Capacities

The levels of existing capacity and capacity under construction are obtained from EIA's Generating Unit Reference File (GURF) except for existing hydroelectric plants. Hydroelectric plants are from the Federal Energy Regulatory Commission (FERC), *Hydroelectric Power Resources of the United States--Developed and Undeveloped*, FERC-0700, January 1, 1980.

New Plant Construction

It is assumed that licensing and construction, which is specified on a plant-by-plant basis, typically takes 10 to 15 years for nuclear plants, 8 years for fossil-fueled steam plants, 6 years for combined-cycle plants, 3 years for turbines, and 5 years for hydroelectric plants. No new construction, except for plants currently planned

or under construction, is assumed for gas-fired steam plants or for nuclear and hydroelectric capacity.

Capital Costs

Capital costs vary significantly according to the location of the new plant. Table B3 contains the capital costs of new plants built in Federal Region 5, which is considered representative of the national average. The estimates for capital costs for new plants in 1983 dollars per kilowatt are based on plants constructed "overnight" and do not include any allowance for funds used during construction (AFUDC) or for escalation. Estimates for coal-fired steam plants were taken from Oak Ridge National Laboratory's Conceptual Capital Cost Model (CONCEPT-5). Nuclear capital costs were obtained from EIA's *Quarterly Progress Report on the Status of Reactor Construction*. The nuclear cost is the capacity-weighted average of all units currently under construction in Federal Region 5. All other figures were based on data taken from DOE's *Data Notebook Generating Technology Assessment*, R-035-DOE-80, January 1980. Note that the costs for low- and medium-sulfur lignite-fired plants are from Federal Regions 8 and 6, respectively, since Region 5 does not use lignite.

Construction Profiles

The annual expenditures (as a percentage of the total construction costs) for new nuclear and coal plants, which account for almost all of the capacity additions

Table B3. Capital Costs for New Plants by Type of Generating Capacity, Federal Region 5
(1985 Dollars per Kilowatt)

Generating Capacity	Cost
Oil/Gas Steam	780
Coal-Fired Steam without Flue Gas Desulfurization	
Bituminous--Low Sulfur	906
Subbituminous--Low Sulfur	936
Lignite--Low Sulfur	1,025
Coal-Fired Steam with Flue Gas Desulfurization	
Bituminous--Low Sulfur	1,004
Bituminous--Medium Sulfur	1,020
Bituminous--High Sulfur	1,072
Subbituminous--Low Sulfur	1,035
Subbituminous--Medium Sulfur	1,048
Lignite--Low Sulfur	1,134
Lignite--Medium Sulfur	1,116
Combined Cycle--Gas	501
Combustion Turbine--Gas	234
Combustion Turbine--Distillate	252
Nuclear Power	2,000
Hydroelectric Power	1,448

Source: Energy Information Administration, Electric Power Division.

Table B4. Annual Shares of Plant Construction Expenditures, Region 5
(Percent)

Plant Type	Years Before Commercial Operation													
	15	14	13	12	11	10	9	8	7	6	5	4	3	2
Nuclear														
10-Year														
Lead Time	--	--	--	--	--	0.2	2.5	9.7	20.2	26.9	23.5	12.8	3.7	0.4
12-Year														
Lead Time	--	--	--	0.1	1.2	5.0	11.6	18.9	22.7	20.3	13.1	5.6	1.4	0.1
14-Year														
Lead Time	--	0	0.7	2.8	6.9	12.3	17.3	19.6	17.7	12.7	6.8	2.6	0.6	0.1
15-Year														
Lead Time	0	0.5	2.1	5.4	9.9	14.6	17.8	17.9	14.8	9.8	5.0	1.8	0.4	0
Coal	--	--	--	--	--	--	--	4.0	14.0	33.0	34.0	11.0	3.0	1.0

Note: For nuclear units completed through 1986, actual expenditure profiles are used; profiles shown in this table are used for nuclear units completed after 1986.

Source: Energy Information Administration, Electric Power Division.

during the forecast period, are shown in Table B4. The capital expenditure profiles are extracted from the CONCEPT-5 model. The nuclear profiles vary by unit, based on lead times for construction.

percent, respectively, in 1984 to 53.0, 12.0, and 35.0 percent, respectively, in 1995.

Cost of Finance

The nominal costs of finance and the financial structure of electric utilities vary according to region. For Region 5, which is considered representative, the assumed nominal costs of finance for debt, preferred equity, and common equity range from 13.3, 12.6, and 16.2 percent, respectively, in 1984 to 10.5, 10.1, and 15.2 percent, respectively, in 1995. The assumed financial structure of electric utilities in terms of debt, preferred equity, and common equity ranges from 52.8, 12.0 and 35.2

Interregional and International Electricity Trade

Transfers of electricity among utilities are adjusted for transmission losses by using an assumed loss factor of 9 percent. Assumptions with respect to net imports of electricity from Canada and Mexico are based on forecasts for 1995 by the Economic Regulatory Administration (Table B5). Interregional transfers of domestically produced power are determined exogenously to reflect the need to balance domestic production and sales to ultimate consumers. Changes in interregional transfers are projected to reflect scheduled plans.

Table B5. Assumptions for Net Regional Transfers of Electricity, 1995
(Trillion Btu)

Federal Region Destination	Source										
	Canada/ Mexico	1	2	3	4	5	6	7	8	9	10
1	69.1	--	15.4	--	--	--	--	--	--	--	--
2	69.1	--	--	79.8	--	--	--	--	--	--	--
3	--	--	--	--	--	--	--	--	--	--	--
4	--	--	--	--	--	--	8.1	3.4	--	--	--
5	46.6	--	--	62.0	14.7	--	--	--	29.0	--	--
6	0.2	--	--	--	--	--	--	3.8	--	--	--
7	12.4	--	--	--	--	0.3	--	--	6.6	--	--
8	33.4	--	--	--	--	--	--	--	--	--	--
9	33.4	--	--	--	--	--	27.3	--	21.7	--	59.4
10	8.4	--	--	--	--	5.8	--	--	162.9	--	--

Source: Energy Information Administration, Electric Power Division.

Appendix C

Historical Statistics of the Electric Utility Industry

Table C1. Historical Statistics of the Electric Utility Industry, 1902-1984

Year	Net Summer Capability ^a (thousand MW)	Net Generation ^b (billion kWh)	Sales to End-Use Sectors ^c (billion kWh)	Electricity Prices ^d (cents/kWh)			
				Residential		Weighted Average All Classes	
				Current	Constant ^e	Current	Constant ^e
1902	1	3	NA	16.20	100.62	NA	NA
1907	2	6	NA	10.50	58.33	NA	NA
1912	5	12	NA	9.10	46.52	NA	NA
1917	9	25	NA	7.52	26.32	NA	NA
1920	13	39	NA	7.45	17.43	NA	NA
1921	14	37	NA	7.39	21.22	NA	NA
1922	15	44	NA	7.38	22.82	NA	NA
1923	16	51	NA	7.20	21.44	NA	NA
1924	18	55	NA	7.20	21.75	NA	NA
1925	22	61	NA	7.30	21.59	NA	NA
1926	24	69	56	7.00	21.01	NA	NA
1927	26	75	61	6.82	21.03	NA	NA
1928	29	83	67	6.63	20.23	NA	NA
1929	31	92	75	6.33	19.32	NA	NA
1930	33	91	75	6.03	18.99	NA	NA
1931	35	87	72	5.78	20.02	NA	NA
1932	35	79	64	5.60	21.82	NA	NA
1933	36	82	66	5.52	21.97	NA	NA
1934	35	87	71	5.33	19.52	NA	NA
1935	35	95	78	5.01	17.97	NA	NA
1936	36	109	90	4.67	16.68	NA	NA
1937	37	119	99	4.30	14.68	NA	NA
1938	39	114	94	4.14	14.45	NA	NA
1939	40	128	106	4.00	14.07	NA	NA
1940	41	142	119	3.84	13.21	NA	NA
1941	44	165	140	3.73	11.94	NA	NA
1942	46	186	159	3.67	10.69	NA	NA
1943	49	218	186	3.60	9.96	NA	NA
1944	51	228	198	3.51	9.48	NA	NA
1945	52	222	194	3.41	8.99	NA	NA
1946	52	223	191	3.22	7.34	NA	NA
1947	54	256	218	3.09	6.24	NA	NA
1948	58	283	241	3.01	5.69	NA	NA
1949	65	291	255	2.95	5.62	NA	NA
1950	71	329	291	2.88	5.38	NA	NA
1951	77	371	330	2.81	4.92	NA	NA
1952	85	399	356	2.77	4.78	NA	NA
1953	96	443	396	2.74	4.66	NA	NA
1954	105	472	424	2.70	4.53	NA	NA
1955	117	547	497	2.65	4.36	NA	NA
1956	123	601	546	2.61	4.16	NA	NA
1957	133	632	576	2.56	3.94	NA	NA
1958	147	645	588	2.54	3.83	NA	NA
1959	160	710	647	2.51	3.71	NA	NA
1960	171	756	688	2.62	3.81	1.82	2.65
1961	184	794	772	2.60	3.75	1.82	2.63
1962	195	855	778	2.56	3.63	1.80	2.55
1963	213	917	833	2.51	3.50	1.77	2.47
1964	226	984	896	2.45	3.37	1.73	2.38
1965	238	1,055	954	2.39	3.21	1.70	2.29
1966	251	1,144	1,035	2.34	3.05	1.66	2.16
1967	271	1,214	1,099	2.31	2.92	1.65	2.09
1968	289	1,329	1,203	2.25	2.73	1.63	1.97
1969	314	1,442	1,314	2.21	2.55	1.63	1.88
1970	340	1,532	1,392	2.22	2.43	1.67	1.83
1971	366	1,613	1,470	2.32	2.42	1.77	1.84
1972	396	1,750	1,595	2.42	2.42	1.86	1.86
1973	440	1,861	1,713	2.54	2.40	1.96	1.85

Table C1. Historical Statistics of the Electric Utility Industry, 1902-1984
(Continued)

Year	Net Summer Capability ^a (thousand MW)	Net Generation ^b (billion kWh)	Sales to End-Use Sectors ^c (billion kWh)	Electricity Prices ^d (cents/kWh)			
				Residential		Weighted Average All Classes	
				Current	Constant ^e	Current	Constant ^e
1974	470	1,867	1,706	3.10	2.69	2.49	2.16
1975	493	1,918	1,747	3.51	2.79	2.92	2.32
1976	522	2,038	1,855	3.73	2.82	3.09	2.33
1977	542	2,124	1,948	4.05	2.89	3.42	2.44
1978	561	2,206	2,018	4.31	2.87	3.69	2.45
1979	577	2,247	2,071	4.64	2.84	3.99	2.44
1980	591	2,286	2,094	5.36	3.00	4.73	2.65
1981	611	2,295	2,147	6.20	3.17	5.46	2.79
1982	627	2,241	2,086	6.86	3.31	6.13	2.96
1983	635	2,310	2,151	7.18	3.33	6.30	2.93
1984	649	2,416	2,278	7.54	3.38	6.52	2.92

^a 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 test at the time of summer peak demand. 1902-1948 data are derived from the Edison Electric Institute (EEI) **Historical Statistics of the Electric Utility Industry Through 1970** (1970), p. 2. 1949-1984 data are from Energy Information Administration, **Annual Energy Review 1985** (AER) (May 1986).

^b 1902-1948 data are from EEI, p. 24. 1949-1984 data are from AER 85.

^c 1926-1948 data are from EEI, p. 60. 1949-1984 data are from AER 85 (Note: Comparably defined EEI data for 1949-1960 are consistently about 3 percent below EIA data shown in this table for the same years).

^d • 1902 data: U.S. Bureau of the Census, **Historical Statistics of the United States, Colonial Times to 1970, Bicentennial Edition, Part 2** (1975), p. 827. • 1907-1959 data: EEI, p. 165. • 1960-1984 data: Energy Information Administration, AER 85. Comparably defined EEI capacity data for 1960-1970 are about 6 percent above EIA data shown in this table for the same year. As a result, apparent price increases shown in the table between 1959 and 1960 reflect changes in the data series and not real price increases.

^e Constant prices calculated in 1972 dollars.

NA=Not available.

Appendix D

Data Sources

Data Sources

Data for the tables in Chapter 1 of the main report were compiled by the Data Analysis Branch, Electric Power Division from the following sources:

- Electrical World, *Directory of Electric Utilities* (New York: McGraw Hill, 1985)
- Rural Electrification Administration, *Rural Electric Borrowers, 1984 Statistical Report* (Washington, DC, 1985)
- Tennessee Valley Authority, *1984 Annual Report, Volume II* (Knoxville, Tennessee, 1985)
- Bonneville Power Administration, *1984 Annual Report* (Portland, Oregon, 1985)
- Southwestern Power Administration, *1984 Annual Report* (Tulsa, Oklahoma, 1985)
- Western Area Power Administration, *Annual Report 1984* (Golden, Colorado, 1985)
- Alaska Power Authority, *Alaska Electric Power Statistics*, 10th Edition (Anchorage, Alaska, December 1985)
- Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities" (Washington, DC, 1984)
- Southeastern Power Administration, *1984 Annual Report* (Elberton, Georgia, 1985)
- Unpublished data from the Bureau of Indian Affairs (Washington, DC), the Western Area Power Administration (Golden, Colorado), and the Association of College and University Housing Officers (Columbus, Ohio)
- American Public Power Association, *1986 Public Power Directory* (Washington, DC, January 1986)
- Moody's Investors Service, *1985 Moody's Municipal and Government Manual* (New York, New York, 1985)
- Energy Information Administration, *Typical Electric Bills* (Washington, DC, 1985)
- Midwest Oil Register, *Directory of Electric Light and Power Companies Operating in the United States* (Tulsa, Oklahoma, 1983)
- Washington Public Power Supply System, *1984 Annual Report* (Richland, Washington, 1985).

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