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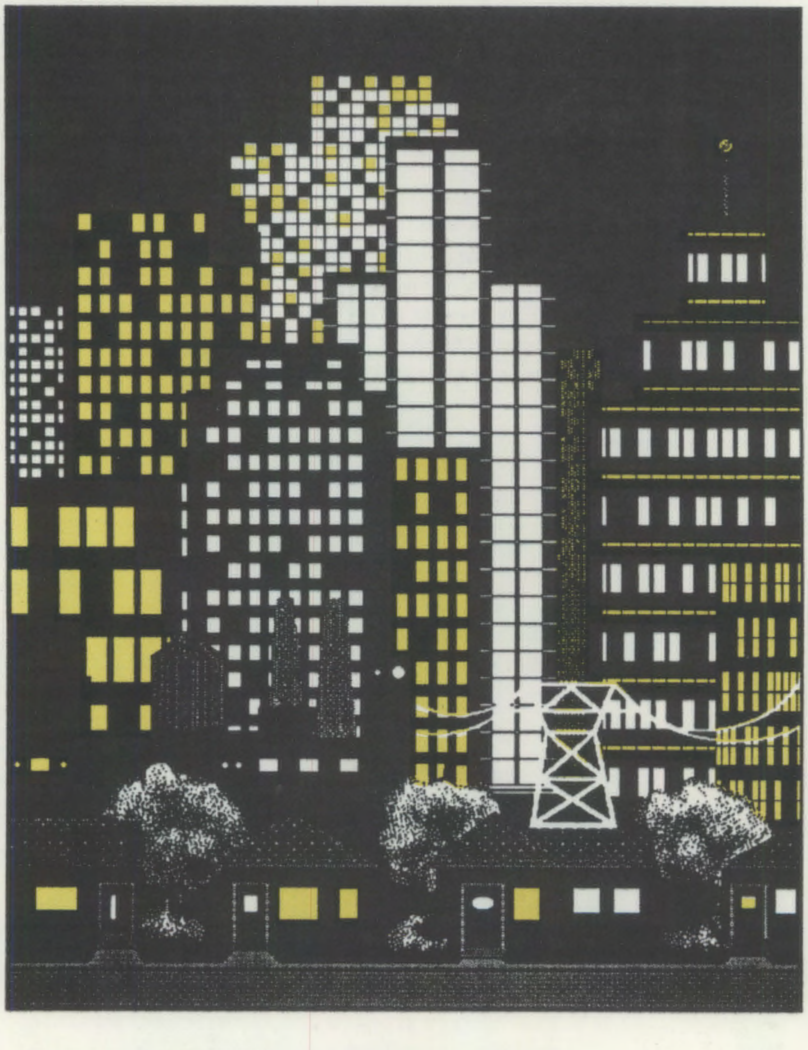
Long-Term Need for New Generating Capacity

March 1987



Prepared for the U.S. Department of Energy
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LONG-TERM NEED FOR NEW GENERATING CAPACITY

C. H. Bloomster
E. T. Merrill

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Pacific Northwest Laboratory
Richland, Washington 99352

ABSTRACT

Electricity demand should continue to grow at about the same rate as GNP creating a need for large amounts of new generating capacity by the year 2000. Only coal and nuclear at this time have the abundant domestic resources and assured technology to meet this need. However, large increase in both coal and nuclear usage will not be acceptable to society without solutions to many of the problems that now deter their increased usage. For coal the problems center around the safety and environmental impacts of increased coal mining and coal combustion. For nuclear the problems center around reactor safety, radioactive waste disposal, financial risk, and nuclear materials safeguards. The fuel requirements and waste generation for coal plants are orders of magnitude greater than for nuclear. Technology improvements and waste management practices must be pursued to mitigate environmental and safety impacts from electricity generation.

LONG-TERM NEED FOR NEW GENERATING CAPACITY

EXECUTIVE SUMMARY

Obsolete generating capacity and the growing demand for electricity is placing this nation closer to an energy crisis. New baseload capacity, beyond that already under construction, will be needed in large amounts between 1992 and 2005 (recent trends point to the late 1990s) to meet projected electricity demand.

Currently, generating capacity is in surplus, but new power plant completions are projected to fall below 4 GW per year in 1990--a 40-year low (nuclear completions will fall to zero). The national long-term growth rate is projected to be near 2.5% per year--a growth rate that will generate a cumulative need for 1100 GW on new baseload capacity by the year 2035 (Table S.1). A rapid recovery from this low point is needed, with new plant completions reaching 30 GW per year by the year 2000 (give or take a few years depending on electricity demand). Orders for new capacity should start by 1990, given the lead time required for new baseload construction.

Only the coal and nuclear options have the abundant domestic resources and assured technology at this time to meet this need. Oil and gas probably have sufficient resources, but they are expected to be more costly and more valuable for uses other than baseload generation. Other electricity generation technologies either do not have sufficient resources or require technological breakthroughs to become competitive on a large scale.

The need for new baseload capacity could be entirely met by either coal or nuclear. The required growth rates for either option are low; the capacity

TABLE S.1. Future Need for New Baseload Capacity

	2005	2015	2035
Cumulative Need, GW	190	490	1100
Probable Bounds, GW	10-400	150-800	600-2000

of the individual steps in either the coal or nuclear fuel cycles should be expandable as needed without encountering supply constraints. The long lead time step (8 to 10 years) in the coal fuel cycle is the expansion of mine capacity. The long lead time steps in the nuclear fuel cycle are the addition of enrichment capacity (6 to 8 years) and the expansion of mine capacity (8 to 10 years). Since the lead times for these steps are about the same as the lead time for power plant deployment, sufficient time for orderly expansion should be available. United States enrichment capacity and uranium mining capacity are currently in surplus, but under scenarios of high nuclear growth and import restrictions new capacity would be required in 20 to 30 years.

Although coal could replace existing nuclear plants over a period of years, an immediate shutdown of existing nuclear capacity would lead to power cutbacks and would severely disrupt the economies in several regions. Nuclear currently generates almost 20% of the electricity nationally, and up to 35% in some regions. Replacing existing nuclear electricity generation with coal would require a 30% increase in coal mining and transport, and subsequently lead to a large increase in emissions. The reserve margin would fall below 20% in five of the nine NERC regions. Thus, load restrictions entailing economic and social costs would probably be required in some regions.

The forces that drive the growing need for new generating capacity are the growing demand for electricity and the need to replace obsolete capacity. The long-term demand for electricity is driven by growth in population, economic growth, and the substitution of electricity for other energy sources; all of these are projected to increase during the time span of this study. There are over 600 GW of installed capacity at present; most of this will be replaced over the 50-year time span of this study. The need for new capacity to replace obsolete capacity is about 2 GW/year today but should increase to over 20 GW/year by 2010.

Electricity demand should continue to grow over the long-term because its usage is closely tied to economic activity. National policies encourage economic growth. From its beginning about 100 years ago, electricity has steadily penetrated the economy with new and diverse uses. Until 1973, electricity usage grew at twice the rate of gross national product (GNP). Since 1973, electricity usage and GNP have increased at about the same rate. The consensus of numerous forecasts is that electricity usage will grow at a rate between 1.5 and 3.5% per year, or about the same as GNP.

The decline in the growth rate of electricity usage since 1973 led to a current surplus of generating capacity. Capacity expansion plans, geared to higher historic growth rates, adapted too slowly to the new conditions even though many plants were cancelled and the construction schedules of others were stretched out. However, the surplus capacity should be gradually absorbed through growth, and shortages in some regions may develop in the early 1990s unless new capacity is added.

As the demand for electricity continues to grow, the need for new power plants will become more evident than it is today. Coal and nuclear, which provide nearly three-fourths of current electricity generation, will be called on to meet most of the need for new capacity. However, large increases in both coal and nuclear usage will not be acceptable to society without solutions to many of the problems cited below. Given the long lead time for research and technology development, planning decisions must be undertaken now on R&D programs needed to assure that acceptable technology will be available to meet the future needs. Solving these problems should be approached with a sense of urgency. Today's surplus will soon disappear. To follow will be demands for new "acceptable" generating technology on a large scale.

Despite their huge potential, both coal and nuclear plants face a number of problems that threaten their future. For coal, the problems center around the safety and environmental impacts of increased coal mining and coal combustion. Notable issues are acid rain, the greenhouse effect, acceptable emission limits, occupational health and safety, mine reclamation, and acid mine drainage. For nuclear, the problems center around reactor safety, radioactive waste disposal, financial risk, and nuclear materials safeguards. Notable issues include liability limits, nuclear proliferation, spent fuel disposal, radiation exposure, licensing simplification, quality assurance, and construction costs and schedules. Resolution of these problems and others will require both technological improvements and institutional innovation to attain the vast energy potential of these resources.

Changing conditions could limit coal production and usage and cause a rapid shift from coal to nuclear. These might include 1) new coal mining regulations related to health and safety, land usage, reclamation, and mine waste; 2) decreased reliability of supply caused by natural or man-made disasters, public opposition, legal actions, labor disputes and other factors; 3) cost increases in mining and rail transport; and 4) new regulations related to gaseous emissions and solid waste disposal. The much larger quantities of fuel required on a continuing basis make coal plants more vulnerable to future supply disruptions and future cost increases than nuclear plants.

For reasons of national energy security, improving the viability of nuclear energy, as one of the two large options currently available, is vital to meeting future electricity growth. New orders for nuclear plants depend primarily on reducing the financial risks now associated with construction and rate-making, but other conditions are also important to the future viability of the nuclear option. These include resolution of the nuclear waste disposal issue, improvements in the licensing process, improvements in technology, increased public and political support, and improvements in the design, construction and operation of nuclear reactors.

The fuel consumption in a coal-fired power plant is roughly 100,000 times greater than in a nuclear plant. That is, about 100,000 tons of coal are consumed for every ton of uranium to generate the same amount of electricity. Therefore, the transportation requirements to the power plant are also about 100,000 times greater for coal than for uranium. However, only about 20 tons of coal must be mined for every ton of uranium ore mined. Most of the uranium ore remains as tailings at the mill site and much of the uranium concentrate shipped from the mills remains as tailings at the enrichment plant. Typical yearly fuel cycle requirements and waste generation for a 1000-MWe power plant are summarized in Table S.2.

Coal-fired power plants with scrubbers produce about 12,000 times as much solid waste on a weight basis as nuclear plants for the same power output. A small fraction of the fly ash and scrubber sludge is used as by-products, but the majority is buried in landfills. Although coal plants generate much

TABLE S.2. Annual Fuel Cycle Requirements, Electricity Generation, and Waste Generation per 1000 MWe (1 GW) Capacity

	Coal	Nuclear
Mining, tons mined	2,900,000	170,000
Mine and Mill Waste (cubic yards)	390,000	120,000
Mine Shipments (tons)	2,500,000	210
Uranium Enrichment (millions of separative work units)	None	0.10
Fuel Fabrication (equivalent number of PWR fuel assemblies)	None	47
Electricity Generation (TWh)[a]	6.1[b]	6.1[b]
Fuel Consumption by Weight (tons coal or uranium)	2,500,000	23
Nonradioactive Waste (cubic yards)	780,000	47
Low-Level Radioactive Waste (cubic yards)	0	82
High-Level Radioactive Waste (cubic yards)	0	14
Gaseous Emissions (tons)		
SO_2[c]	4,900	0
NO_x[c]	16,000	0
CO_2	7,200,000	0
F	0	0.04

(a) TWh = one billion kWh.
(b) 70% capacity factor.
(c) Based on emission limits.

greater quantities of waste than nuclear plants, comparatively low-cost technology is in place to meet existing disposal regulations. Therefore, solid waste disposal should not deter increased coal usage under existing regulations.

Nearly all of the coal converts into gaseous products of combustion, predominately CO_2. Although CO_2 emissions are not presently regulated, atmospheric warming (the greenhouse effect) is a potential concern in the long-term. About 3 tons of CO_2 are produced for every ton of coal burned. Coal combustion also produces SO_2 and NO_x. SO_2 and NO_x emissions are regulated now, and more stringent regulations are a potential concern. In contrast, nuclear fission produces no CO_2, no SO_2, no NO_x, and a negligible quantity of gaseous emissions.

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GLOSSARY

Baseload Capacity: The generating equipment normally operated to serve loads on an around-the-clock basis.

Boiling-Water Reactor (BWR): A light-water reactor in which water, used as both coolant and moderator, is allowed to boil in the reactor core. The resulting steam can be used directly to drive a turbine.

Capability: The maximum generating capacity available at a given instant of time, usually the summer peak. The capability is often less than the rated capacity because of deratings caused by high cooling water temperatures in the heat rejection system and other factors.

Capacity: The load for which a generating unit is rated, either by the user or by the manufacturer.

Capacity Factor: The ratio of the electricity produced by a generating unit, for the period of time considered, to the energy that could have been produced at continuous full-power operation during the same period.

Nameplate Capacity: The nominal electrical output of a generator, as specified by the manufacturer.

Elasticities of Demand: The proportionate change in the quantity of energy demanded resulting from a proportionate change in price. The income elasticity of demand is defined similarly for changes in income. Elasticities are calculated as the ratio of the respective proportionate changes.

Generation (Electricity): The process of producing electric energy from other forms of energy; also, the amount of electric energy produced, expressed in watthours (Wh).

> Gross Generation: The total amount of electric energy produced by generating units in a generating station or stations, measured at the generator terminals.
>
> Net Generation: Gross generation less the electric energy consumed at the generating station for station use. (Energy required for pumping at pumped-storage plants is regarded as plant use and is subtracted from gross generation or from hydroelectric generation.)

Gigawatt (GW): One billion watts.

Gross National Product (GNP): A measure of the final output of goods and services by citizens of a country, whether living at home or in foreign countries. GNP comprises GDP and factor incomes from abroad accruing to residents, less the income earned in the domestic economy accruing to citizens of other countries.

Intermediate or Load-following Capacity: Generating capacity that operates on an intermediate (between the baseload and peaking capacities) basis.

Kilowatt (kW): One thousand watts.

Kilowatthour (kWh): One thousand watthours.

Light Water: Ordinary water (H_2O), as distinguished form heavy water or deuterium oxide (D_2O).

Light-Water Reactor (LWR): A nuclear reactor that uses water as the primary coolant and moderator, with slightly enriched uranium as fuel. There are two types of commercial light-water reactor--the boiling-water reactor (BWR) and the pressurized-water reactor (PWR).

Load Following: Regulation of the power output of electric generators within a prescribed area in response to changes in system frequency, tieline loading, or the relation of these to each other, so as to maintain the scheduled system frequency and/or the established interchange with other areas within predetermined limits.

Megawatt (MW): One million watts.

Megawatthour (MWh): One million watthours.

NERC (North American Electric Reliability Council): An organization of the electric utility industry founded to promote the reliability of bulk power supply in the electric utility systems of North America.

Nuclear Power Plant: A single- or multi-unit facility in which heat produced in a reactor(s) by the fissioning of nuclear fuel is used to drive a steam turbine(s).

Nuclear Reactor: An apparatus in which the nuclear fission chain can be initiated, maintained, and controlled so that energy is released at a specific rate. The reactor apparatus includes fissionable material (fuel) such as uranium or plutonium; fertile material; moderating material (unless it is a fast reactor); a heavy-walled pressure vessel; shielding to protect personnel; provision for heat removal; and control elements and instrumentation.

Peaking Capacity: Generating capacity operated for short periods of time to meet peak demands on a daily or seasonal basis.

Peak Demand: In this report peak demand usually refers to the highest annual national demand: This is the sum of the peak annual demands in each region. The regional peaks are non-coincident. There are daily peak demands and seasonal peak demands for which peaking capacity is required.

Plutonium (Pu): A heavy, fissionable, radioactive, metallic element (atomic number 94). Plutonium occurs in nature in trace amounts. It can also be produced as a byproduct of the fission reaction in a uranium-field nuclear reactor and can be recovered for future use.

Pressurized-Water Reactor (PWR): A nuclear reactor in which heat is transferred from the core to a heat exchanger via water kept under high pressure, so that high temperatures can be maintained in the primary system without boiling the water. Steam is generated in a secondary circuit.

Reliability: The degree to which the performance of the elements of a bulk power electric system results in power being delivered to consumers within accepted standards and in the amount desired.

Reserve Margin: The installed capacity above the peak demand, defined as, (capacity less peak demand)/peak demand, and expressed in percent.

Separative Work Unit (SWU): A measure of the effort expended to separate a quantity of uranium of a given assay into two components, one having a higher percentage of uranium-235 and one having a lower percentage.

Summer Capability: The gross electrical output measured at the output terminals of the turbine generator(s) at the summer peak.

Terawatthour (TWh): One trillion (10^{12}) watthours.

Uranium (U): A heavy, naturally radioactive, metallic element (atomic number 92). Its two principally occurring isotopes are uranium-235 and uranium-238. Uranium-235 is indispensable to the nuclear industry, because it is the only isotope existing in nature to any appreciable extent that is fissionable by thermal neutrons. Uranium-238 is also important, because it absorbs neutrons to produce a radioactive isotope that subsequently decays to plutonium-239, an isotope that also is fissionable by thermal neutrons.

INTRODUCTION

Much controversy surrounds the future demand for electricity, the future need for large generating stations, and the future need for nuclear power. Generation capacity is currently in surplus in most regions. Construction of many large power plants, both coal and nuclear, has been cancelled in recent years. Yet the Senate recently held hearings (Senate 85) on the "potential for serious regional shortages of electric power... by the early 1990s." Such shortages could develop from an unanticipated increase in demand. At the present time, uncertainty in the size of the future demand for electricity is high. Price increases, conservation, and shifts in the economy have sharply reduced the growth rate in electrical demand from 7% per year prior to 1973 to 2.5% per year since 1973. This drop in growth rate, coupled with lengthening licensing and construction periods, have added to the uncertainties in planning capacity additions.

In this study, we examine the potential demand for electricity over the long-term to the year 2035. This 50-year period was selected partly because of the long time required to deploy new generating technology and partly to provide a sufficient time span in which to consider the impacts of retiring most of the current capacity. The objectives of this study are to 1) estimate the potential need for new baseload generating capacity; 2) evaluate some of the implications of meeting the need with coal plants only, with nuclear plants only, and with a combination of coal and nuclear plants; and 3) provide a perspective for long-term research and development planning needs for developing improved technology and avoiding potential supply problems.

In 1986, electricity in the United States was generated mostly by coal (56%), followed by nuclear (18%), hydro (10%), natural gas (11%), petroleum (4%), and other sources (1%).[a] The generating capability at the summer peak was 636 GW. The summer peak demand was 475 GW, and the reserve margin was 34%.

The North American Electric Reliability Council (NERC) annually makes 10-year forecasts of electricity demand and capacity. In the period from 1986

(a) October 1986 forecast by NERC (NERC 86, p. 33). Final 1986 data not available at time of writing.

to 1995 most of the new capacity installed will be coal and nuclear. Coal capacity is scheduled to increase 33 GW from 272 GW in 1985 to 305 GW in 1995. Nuclear capacity is scheduled to increase 36 GW, from 71 to 107 GW. Hydro capacity is scheduled to remain about the same at 70 GW. Natural gas capacity is scheduled to drop 2 GW to 42 GW. Oil capacity is scheduled to drop 3 GW to 57 GW. Other types of capacity (geothermal, wind, solar, cogeneration, and biomass) is scheduled to increase from 3 to 18 GW. Dual (oil/gas) fuel capacity is scheduled to increase 2 GW to 89 GW. Retirements of 12 GW in the period to 1995 are planned; these are primarily small petroleum and natural gas units (NERC 86). The above capacities refer to the summer capability.

In this study, we treat electricity demand from a national standpoint because our primary concern is with the aggregate need for new capacity in the U.S. over the long term. Historically, the national electricity demand is strongly related to the gross national product, which is used as a predictor in most forecasts. Although utilities plan and add capacity on a regional basis, there is much commonality between regions in the supply options and in the economic factors that determine demand. The differences between regions in the supply options are primarily related to the transportation costs of fuel and the availability of indigenous alternative energy resources.

The primary focus in this study is the need for baseload generating capacity. Baseload capacity operates over extended periods of time without interruption. Load-following plants operate intermittently, usually cycling on a daily basis. Peaking plants operate for short periods of time, hours or minutes, during the peak loads. Baseload plants produce about 80% of the power generated.

The base year for this study was 1984. At the time of initiation this was the latest year for which complete data were available. More recent data, however, is provided where available. Data for 1985 show an increase in electricity demand of 2.2% over 1984, and an increase in the summer peak demand of 2.1% over 1984 (NERC 1986, pp. 10 and 15).

The remainder of this report is organized in five sections. The first section, Projections of Electricity Demand, analyzes recent long range projections and discusses the factors that affect electricity demand. The second section, Projections of the Need for New Generating Capacity, estimates the long-term needs for new capacity under three scenarios. The third section, Supply Options, discusses the current electricity supply and summarizes future options. The fourth section, Resource Consumption and Waste Generation, compares coal and nuclear fuel cycles currently and under the three long-term scenarios. In the fifth section, Discussion and Conclusions, the implications of the data are presented.

PROJECTIONS OF ELECTRICITY DEMAND

SUMMARY

The economic and social costs of inaccurate near-term electricity demand projections can be large because of the importance of electricity generation in our society. In retrospect, utility planning was inadequate to react accurately to the oil embargo in 1973 resulting in an installed national capacity base that now leads projected needs by about 4 years.

Current capacity expansion plans bring forecasted capacity in line with projected need in 1994. However, these plans are based on growth projections that tend to be low compared to most. This suggests the possibility of shortages within the next decade. Because of the assumed low growth rates now used for planning, the potential for new large excesses in capacity to emerge is low in the absence of a prolonged decline in demand.

Nearly all sources project electricity demand to grow at an annual rate between 1.5% and 3.5%. Growth in electricity demand is closely tied to growth in the GNP. Projections of the ratio of growth in electricity demand to growth in the GNP range from 0.6% to 1.4% with an average of about unity.

NATIONAL PROJECTIONS

Numerous organizations project electricity demand (Appendix A). Nearly all of the recent projections fall within a range of growth rates varying from 1.5% to 3.5% per year, using 1983 as a base year (Figure 1). On the low side are a few outliers that would require negative growth rates. On the high side are a few outliers that would require growth rates up to 4.5%. These projections are used in this study to estimate the probable bounds for electricity demand in the near term and are extrapolated to estimate the bounds out to the year 2035.

Most of the projections are derived from imputed relationships between electricity demand and economic activity. Gross national product and disposable income are measures of economic activity usually used to project electricity demand. Price elasticity, expressed as either real electricity prices or

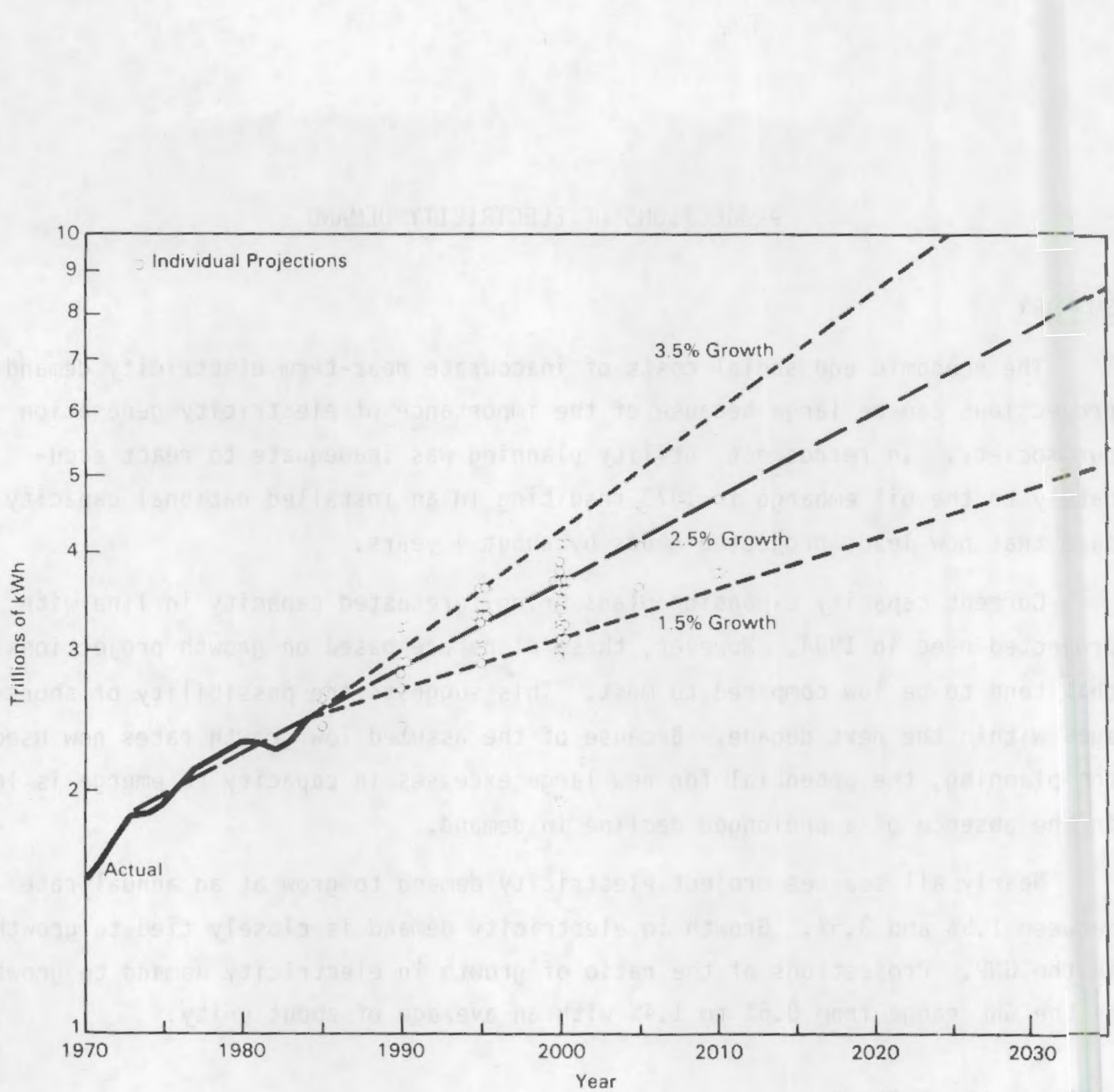

FIGURE 1. Projections of Electricity Demand

as the ratio of electricity prices to other energy prices, enters some econometric models on which projections are based. Some projections are simply based on historic trends, and others are based on per capita consumption. Forecasting methods gaining increased use are based on the end uses of electricity; these methods estimate changes in the consumption of electricity by specific consumers such as the aluminum industry or the residential sector. The end use forecasts are then aggregated (Senate 85, pp. 57-280; Hy 85, pp. 94-102; DOE 85, pp. 28-37; DOE 83; NRC 86; Se 85; OTA 84, pp. 29-41; DOE 84, pp. 5-28).

REGIONAL PROJECTIONS

Different parts of the nation are expected to grow at different rates. Recent projections (NERC 85) of peak loads and electricity demand by NERC region are shown in Table 1.[a] Compare the projected annual growth rates in energy demand (the last four columns in Table 1). Note that the growth rates projected by three other forecasters (last three columns) are on average, higher than the NERC forecasts. Because of the slight difference in geographical boundaries, the forecasts are not exactly comparable. Since the NERC capacity projections reflect individual utility plans, this raises the possibility of regional and national energy shortages if the other forecasts are correct.

IMPORTANCE OF LONG-TERM AND NEAR-TERM PROJECTIONS

The economic and social costs of inaccurate projections[b] could be large because of the importance of electricity generation in our society. New base-load capacity, using existing coal or nuclear technology, now requires a lead time of 8 years or more for licensing and construction. The lead time from initial research and development to commercialization of a new generating technology can exceed 20 years.

Long-term projections of electricity supply needs are important to provide a basis for making business decisions by industries and utility organizations involved in energy supply as well as industrial consumers. In addition, they

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(a) The NERC projections and planned capacity additions are an aggregation of individual utility system projections and plans.

(b) The ability to make accurate projections depends on the predictability of future events. In cases involving stable systems, as for example the solar system, long range predictions, such as eclipses, can be made with great accuracy. In systems involving human activities, the ability to predict future events is far more uncertain. The events surrounding the rise and fall in the price of petroleum over the last decade provide ample evidence. In many cases, long term economic projections are more accurate than short term forecasts since short term vagaries are eliminated. However, when dislocations occur in the long term trend, as occurred in 1973 for electricity demand, long term projections made prior to the dislocation can be far off.

TABLE 1. Projected Regional Growth Rates in Electricity Demand and Peak Load

	NERC Projections						Other Projections		
	Peak Load			Energy Demand			Energy Demand (Annual Growth Rate, %)		
	GW		Annual Growth	Billions of kWh		Annual Growth			
NERC Regions[a]	1984	1994	Rate, %	1984	1994	Rate, %	DOE[b]	DRI[c]	Wharton[c]
ECAR	65.9	81.2	2.1	383	465	2.0	3.0	2.9	2.7
ERCOT	36.9	52.4	3.6	185	267	3.7	3.6	2.7	3.2
MAAC	35.4	39.3	1.1	186	220	1.7	3.1	2.9	3.0
MAIN	35.2	40.5	1.4	171	207	1.9	3.0	2.9	2.7
MAPP-US	20.7	26.5	2.5	105	136	2.6	2.6	2.0	2.1
NPCC-US	38.1	45.5	1.8	217	256	1.7	(d)	3.2	(d)
SERC	93.4	121.9	2.7	503	654	2.7	3.5	2.8	(d)
SPP	45.6	59.4	2.7	226	288	2.5	3.6	2.7	3.2
WSCC	80.0	100.1	2.3	469	588	2.3	3.5	3.5	2.6
NERC-US Total	451.2	566.8	2.3	2446	3081	2.3	3.2	2.9	2.8
SUBREGIONS									
New York[e]	21.9	25.1	1.4	124	141	1.3	2.1		2.3
New England[e]	16.3	20.4	2.4	93	115	2.1	2.3		2.9
TVA[f]	18.5	24.9	3.0	111	138	2.2			1.9
SERC<TVA[f]	74.9	97.0	2.6	391	516	2.8			3.4

(a) NERC Regions are shown in Appendix H.
(b) Middle case to 1995.
(c) Senate 85, pp. 125, 151.
(d) Projected by subregion below.
(e) Subregions of NPCC - US.
(f) Subregions of SERC.

are necessary to plan and perform research and development activities necessary to yield a high probability that future needs can be met at low costs with minimum impact to the environment.

The absolute accuracy of long-term projections is not as important as for near-term projections assuming that projections are frequently updated and that energy supply strategies and associated R&D programs are appropriately re-evaluated to reflect changes in projections. However, it must be recognized that if there is a large mismatch between long-term projections and realizations, then strategies developed for meeting long-term needs may not be appropriate. For example, over-prediction of electricity demand growth rates in the early 1970s led to supply strategies that would have led to an early introduction of both nuclear breeder reactors and recycling of uranium in light-water reactors (LWR). In the future, under-prediction of demand could similarly result in non-optimum supply strategies.

Accurate near-term projections are essential in order to avoid disruptions in economic and social activity that can be caused by either shortages of efficient generating capacity or by an excess capacity of capital-intensive plants.

Inaccurate near-term projections on the low side could result in suppliers having to utilize inefficient high cost power sources or in consumers experiencing power shortages. Inaccurate projections on the high side could result in over-building, and subsequent underutilization, of capital-intensive plants. As demonstrated in the recent past, over-building can threaten the financial viability of the utilities involved and can have a dramatic impact on rates charged to the consumers.

Assumptions about the future are necessary for today's business decisions and provide a basis for planning activities. Therefore, long-term projections are important, but not in an absolute sense since plans can be periodically revised. Long-range planning is required to efficiently meet projected demands at lowest cost, particularly taking into consideration the long lead time required for power plant construction and licensing. Further, the time from the initial R&D work through the introduction and commercialization of a new generating technology can easily exceed 20 years.

The electric utility industry through the NERC annually makes a 10-year forecast of peak demands (NERC 85). The inability of utility planning to react accurately to the oil embargo in 1973 and subsequent events is illustrated in the series of 10-year planning projections since 1974 (Figure 2). Each year NERC reduced the projected growth rate about 10% from the previous year. After 10 years, the peak load projections finally aligned with the post 1973 actual trend. An EPRI report summary concluded that "the overoptimism of the industry forecasts after 1974 was due to the unanticipated slowdown in the growth of the economy, the unexpected continuation of high electricity prices, and an underestimation of the full extent of load sensitivity to price" (EPRI 85).

Orders for new capacity were based on projections of peak load. As the projections of peak demand were gradually reduced, the utility systems adjusted through cancellations and stretch outs of construction projects. In 1984, the installed capacity was 604 GW, about 100 GW below the forecast peak demand made

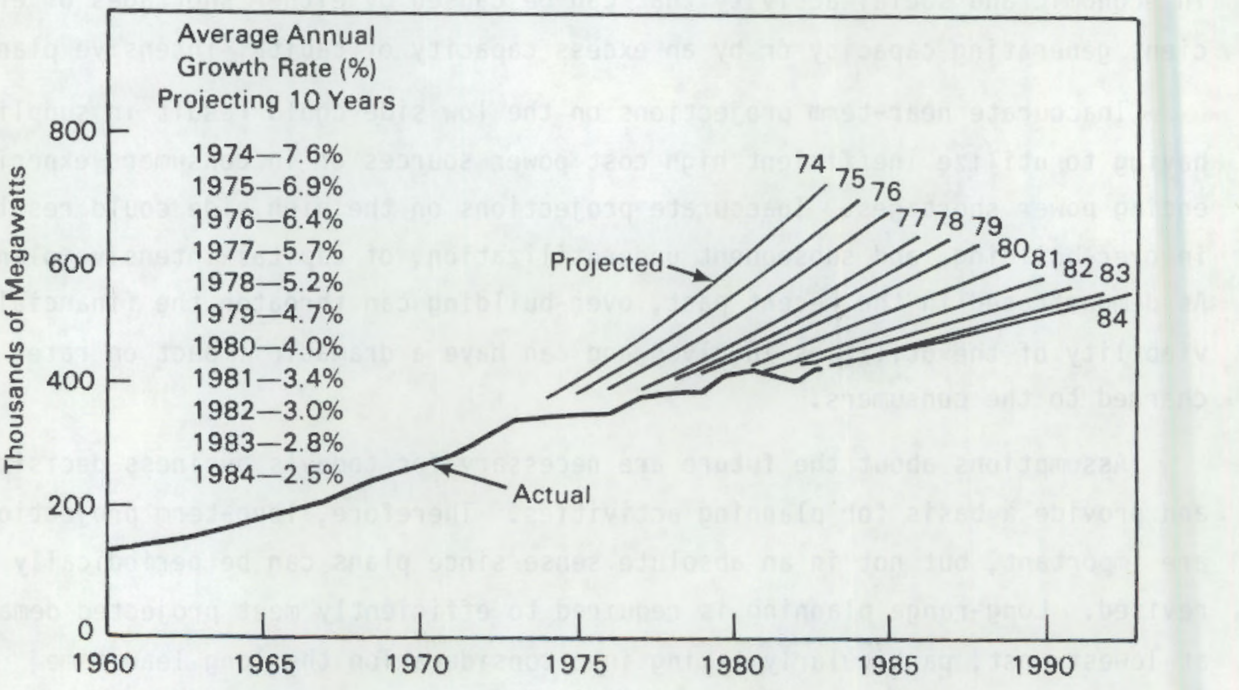


FIGURE 2. NERC Summer Peak Demand Projections--Comparison of Annual Ten-Year Forecasts for the United States

Source: North American Electric Reliability Council, Electric Power Supply and Demand, 1984-1993, published 1984, p. 5.

in 1974. The actual peak demand in 1984 was 451 GW, about 250 GW below the forecast made in 1974. The 1984 installed capacity was sufficient to meet 1988 peak load projections assuming a 2.5% growth rate and a 20% reserve margin. Thus, on a national basis, the surplus of installed generating capacity was about 4 years of capacity growth. Some regions are not in surplus, and, as discussed later, the appropriateness of a 20% reserve margin has been questioned. Also, 18% of the capacity was fueled by petroleum and 14% was fueled by natural gas. Past policies (e.g., Fuel Use Act, Public Law 95-620) generally discouraged use of these energy sources for electricity generation.

Until 1973, electricity demand grew rapidly (DOE 85a, pp. 60-61) and excesses in capacity, if any, could be worked off quickly. After 1973, demand slowed abruptly but capacity expansion did not (Figure 3). Excess capacity quickly developed and persists to this day. Capacity expansion plans have been revised downward bringing forecasted capacity in line with projected need by about 1994. This sets up a potential shortfall situation if demand increases abruptly. On the other side, the potential for new large excesses in capacity to emerge is now low unless a prolonged decline in demand develops.

FACTORS AFFECTING ELECTRICITY DEMAND

One reason for the decline in growth rate since 1973 is the increase in real electricity prices (Figure 4). Prior to 1972 real electricity prices steadily declined. The residential price and the weighted average price for all classes are shown in Figure 4 (DOE 85a, pp. 60-61). The weighted average price for all classes of services is about 12% below the residential price. Steep increases in electricity prices followed the large increases in petroleum prices by the Organization of Petroleum Exporting Countries (OPEC). Over the short term price elasticity is relatively low (-0.2) and electricity usage is little affected by price changes. However, over the long-term, price elasticity approaches unity and electricity usage responds inversely to price changes (Hy 85, p. 41).

Econometric studies link electricity demand to economic activity (real GNP and real disposable income, see Figure 5) and climate (heating and cooling degree days) in addition to price. Electricity demand and real GNP have grown

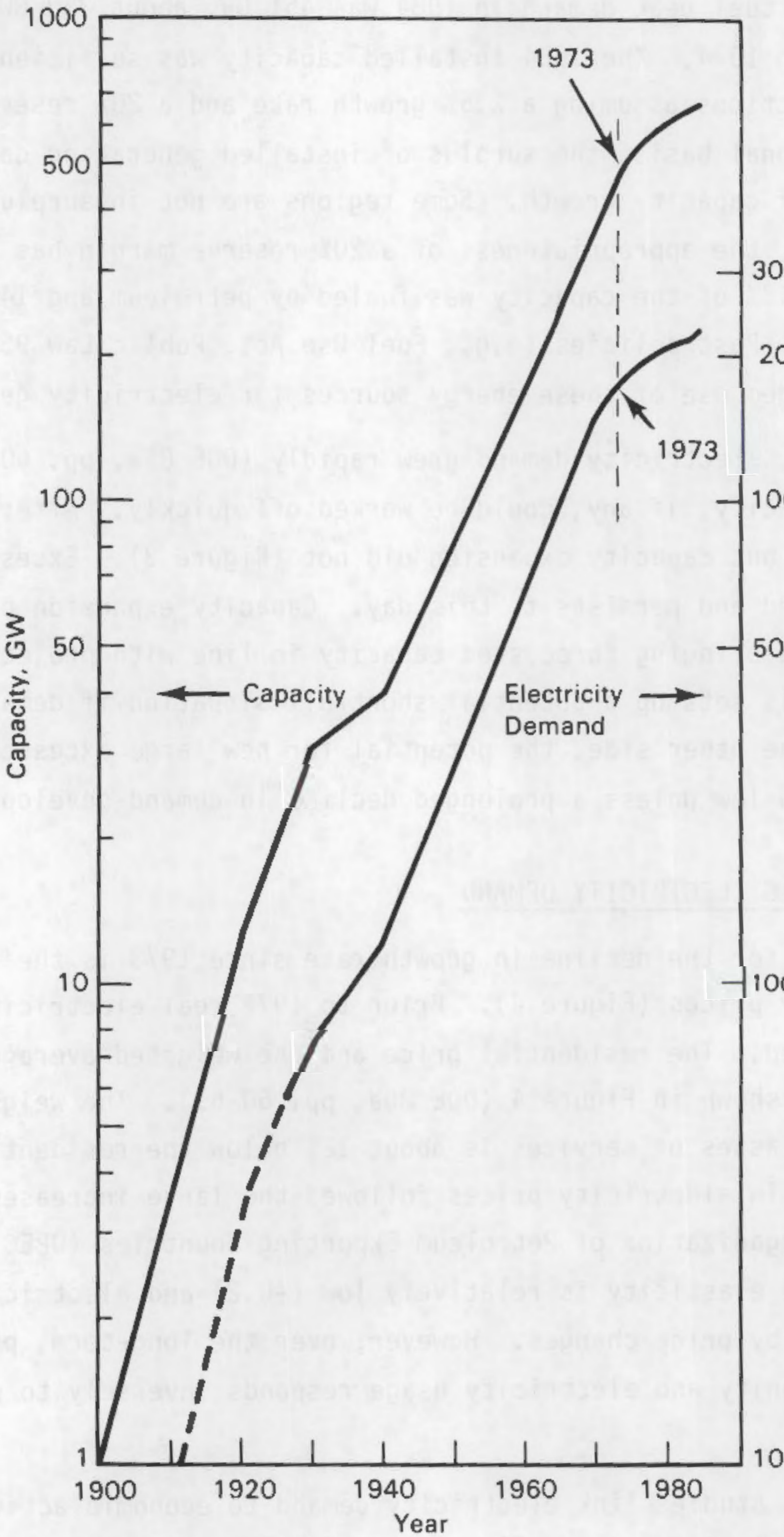


FIGURE 3. Historic Growth of Electricity Demand and Generating Capacity

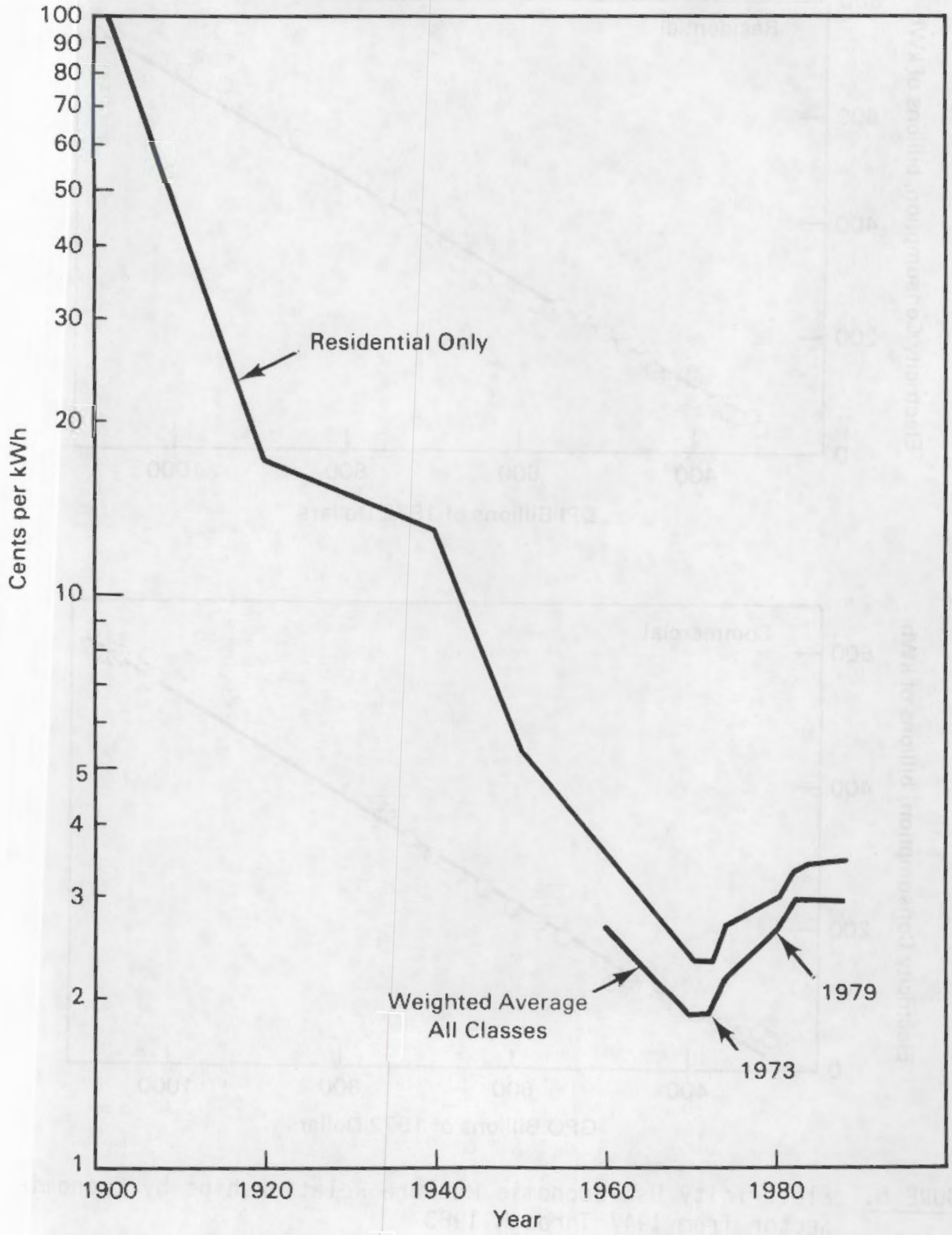


FIGURE 4. Historic Electricity Prices in Constant 1972 Dollars

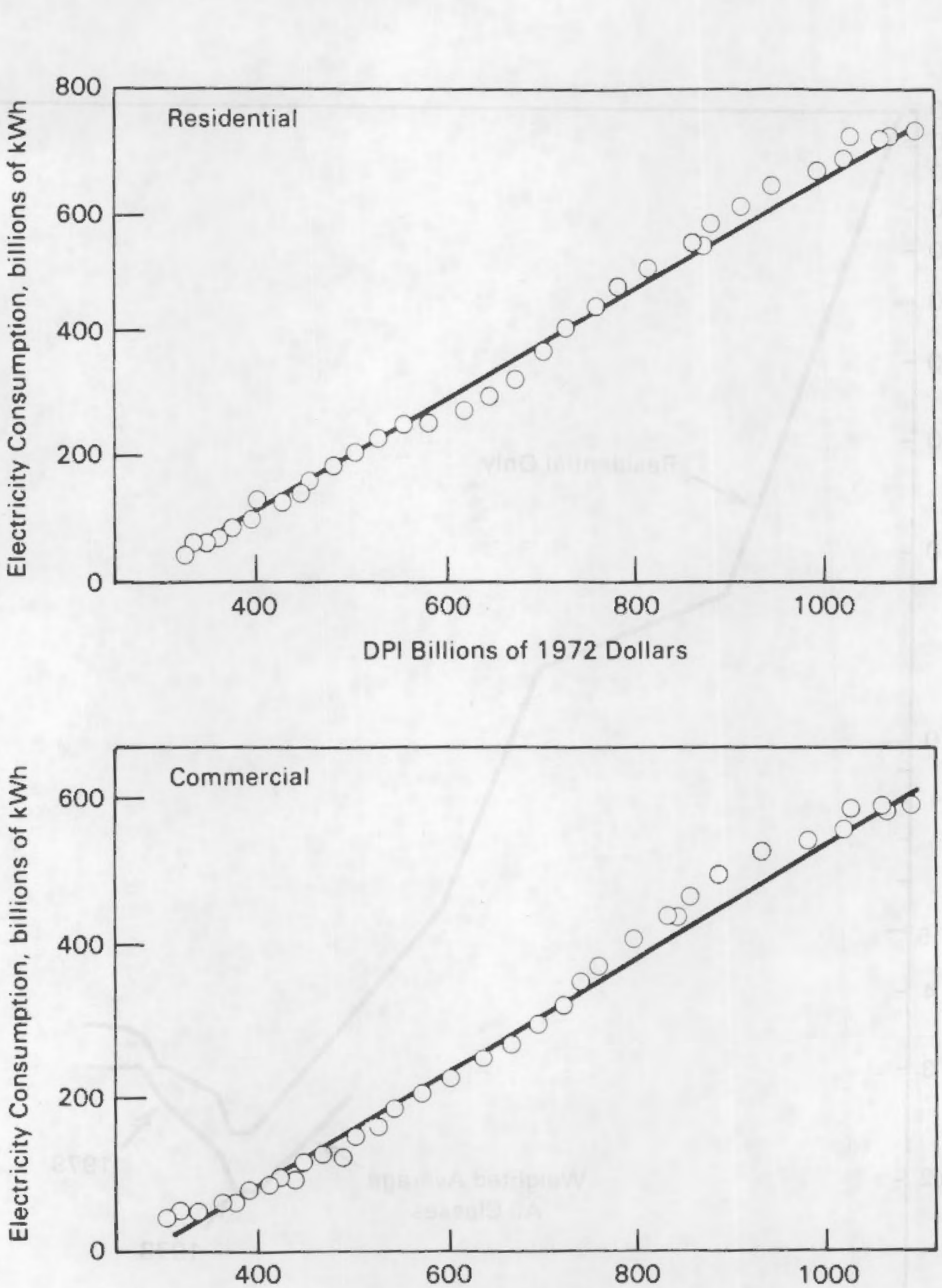


FIGURE 5. Electricity Use-Economic Measure Relationships by Economic Sector from 1947 Through 1983

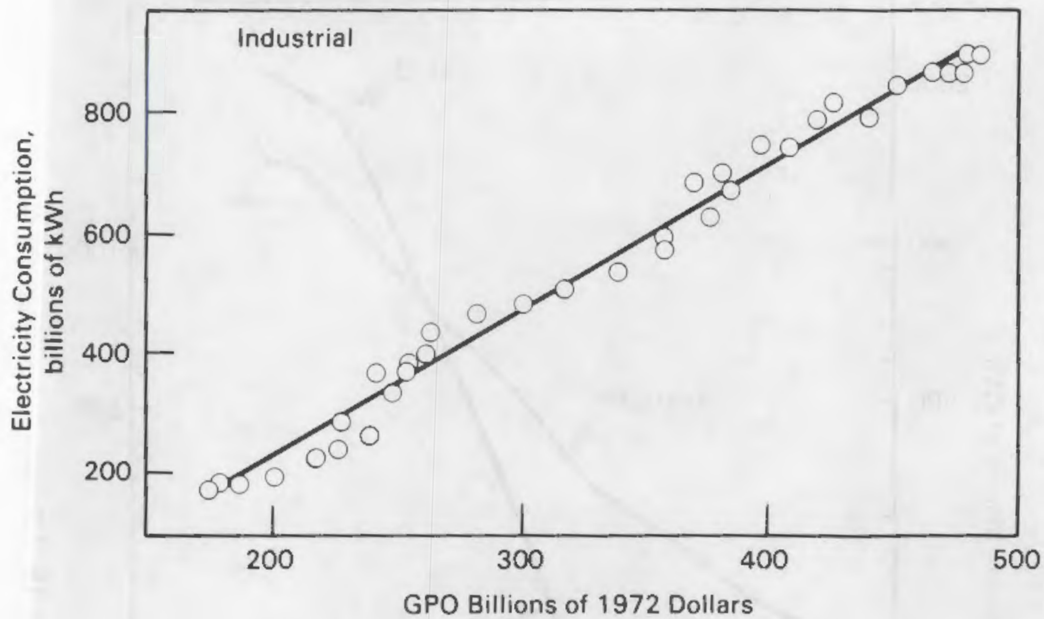


FIGURE 5. (contd)

Note: Different scales are used for the three sectors to highlight the linearity of the electricity use-economic output relationship within sectors. Based on data from Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry, various issues; U.S. Department of Commerce, Bureau of Economic Analysis, The National Income and Product Accounts of the United States, 1929-76, Statistical Tables; and Survey of Current Business, various issues. Dollar values are shown for Disposable Personal Income (DPI) and Gross Product Originating (GPO).

Source: Compilation and figure by Energy Study Center, Electric Power Research Institute, Palo Alto, California. This figure is taken from NRC 86, p. 28.

consistently over time (Figure 6). The growth in electricity demand exceeds GNP growth by a factor of two through 1973. Since 1973, electricity growth generally matches GNP growth (Figure 7). Studies of the relationship between electricity demand and GNP show a positive correlation with an elasticity of 0.5 for the short run and 0.8 for the long run (Hy 85, p. 44). Recent projections (Appendix B) of the ratio of electricity growth to real GNP growth range from 0.6 to 1.4. As noted earlier, many econometric models use forecasts of GNP to project electricity demand.

Weather strongly affects electricity demand (DOE 85b, pp. 18-20). Peak loads usually coincide with temperature extremes. Air conditioning, common in

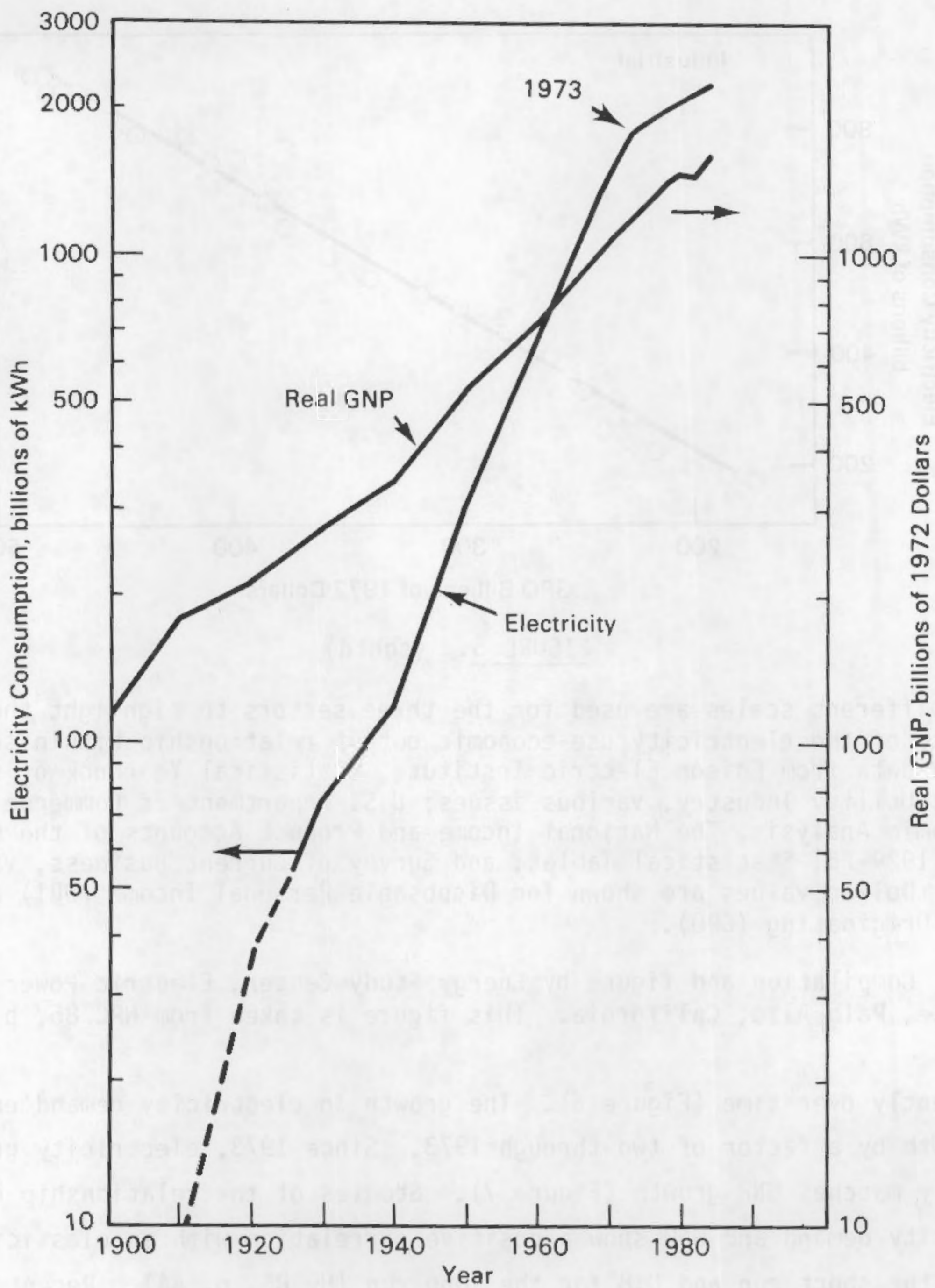
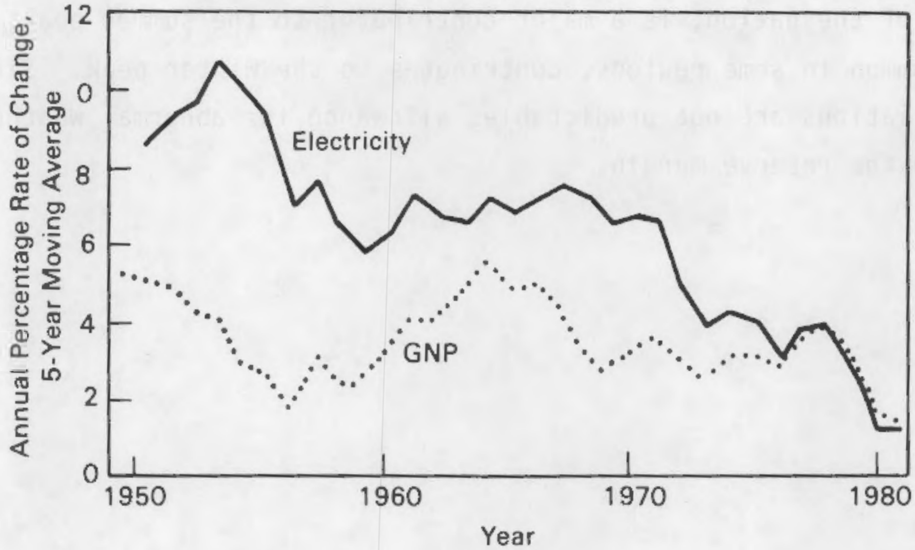
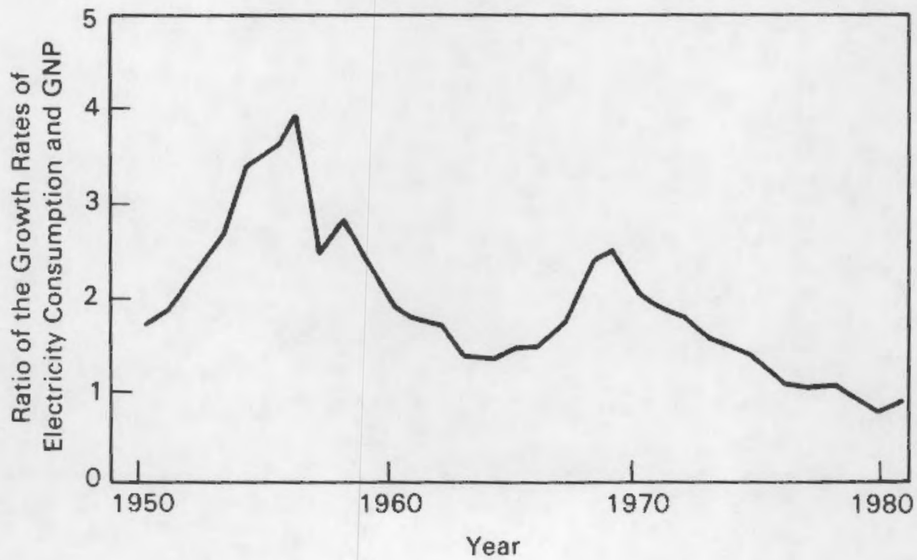


FIGURE 6. Historic Growth in Electricity Demand and Real GNP



a)



b)

FIGURE 7. Growth Rates of United States Electricity Use and GNP (a) and Ratio of the Growth Rates (b)

Sources: Based on data from Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry, various issues; U.S. Department of Commerce, Bureau of Economic Analysis, National Income and Product Accounts of the United States, 1929-76, Statistical Tables; and Survey of Current Business, various issues (from NRC 86, p. 25).

most parts of the nation, is a major contributor to the summer peak. Electric heating, common in some regions, contributes to the winter peak. Since yearly weather variations are not predictable, allowance for abnormal weather must be included in the reserve margin.

PROJECTIONS OF THE NEED FOR NEW GENERATING CAPACITY

SUMMARY

The need for new generating capacity derives from growth in peak demand, the need for reserve capacity, and the replacement of obsolete capacity. Current 10-year utility planning is based on an average annual growth in peak demand of 2.3% and an average annual growth in generating capacity of 1.7%. This will reduce the reserve margin, on a nationwide basis, from a current value of over 34% to a value closer to optimum of about 26% in 1994. Utility f recasts predicted summer peak demand of 567 GW in 1994 and a summer generating capacity of 712 GW. Most of this new capacity is currently under construction. Of the 108 GW of planned capacity additions between 1985 and 1994, 50 GW will be supplied by coal units and 50 GW will be supplied by nuclear units.

The average lifetime of power plants and the average age of operating plants is increasing. Through 1985, the average age of plants at retirement is 36 years. Plants slated for retirement through the year 2000 will have an average age of 37 years; however, more plants will continue to operate beyond that age. The average age of installed capacity will reach 30 years in 1995, up from the 24 years currently.

The long-term need for new generating capacity is estimated for three scenarios. The scenarios were selected to represent the projected "most likely" situation and high and low extremes. Taking into account currently scheduled capacity additions, additional (currently unscheduled) baseload capacity is required by 1992 under the high scenario, by 1995 under the middle scenario, and by 2005 for the low scenario. In all scenarios, once reserve margins reach target values, annual requirements for new capacity additions increase substantially.

CAPACITY PLANNING

The need for new generating capacity is derived from three sources: 1) the growth in peak demand, 2) the replacement of obsolete capacity, and 3) the need for reserve capacity. Generating capacity is added, as needed, to meet the projected peak demand, adding a reserve margin to ensure reliability.

Peak Load

The peak load and the annual energy demand are the important variables for capacity planning. The peak load is more difficult to forecast than energy demand because of its greater sensitivity to weather and end-use patterns. However, over the long run the national peak load and annual energy demand track each other rather closely (Figure 8) (Hy 85, p. 50). Although the peak load determines the amount of capacity needed, the annual energy demand, as reflected by the load duration curve, determines the type of capacity needed to meet reliability standards and achieve the lowest cost.

The need for each type of capacity is determined by the shape of the load duration curve. A typical load duration curve is illustrated in Figure 9. The three types of capacity (base, intermediate, and peak) are shown on the right vertical axis. The boundaries between each type are somewhat arbitrary. Assuming that the area, M, under the line ABC represents the electricity generated by the baseload capacity, then the average capacity factor for the baseload capacity is M/(M+N). Similarly, assuming that the area P is generated by the intermediate load capacity, then the average capacity factor for the intermediate load capacity is P/(P+Q). Correspondingly, the average capacity factor for the peak load capacity is R/(R+S). Collectively, the average capacity factor of the entire system is (R+P+M)/(R+P+M+S+Q+N). The fraction of electricity generated by the baseload capacity is M/(M+P+R); this is typically on the order of 80% in many systems. Note that if outages occur in the baseload capacity, particularly during the hours from A to B, the baseload capacity would not be able to supply M amount of energy. The deficit in that case would be made up by the other capacity. The area N is mainly used for scheduled outages of base load capacity.

The distribution of the need for baseload or peak load capacity is profoundly impacted by the shape of the load duration curve. This is easily illustrated by two hypothetical extreme examples (Figure 10). In Figure 10a, the need for peaking capacity far exceeds the need for baseload capacity. In Figure 10b, the reverse is true.

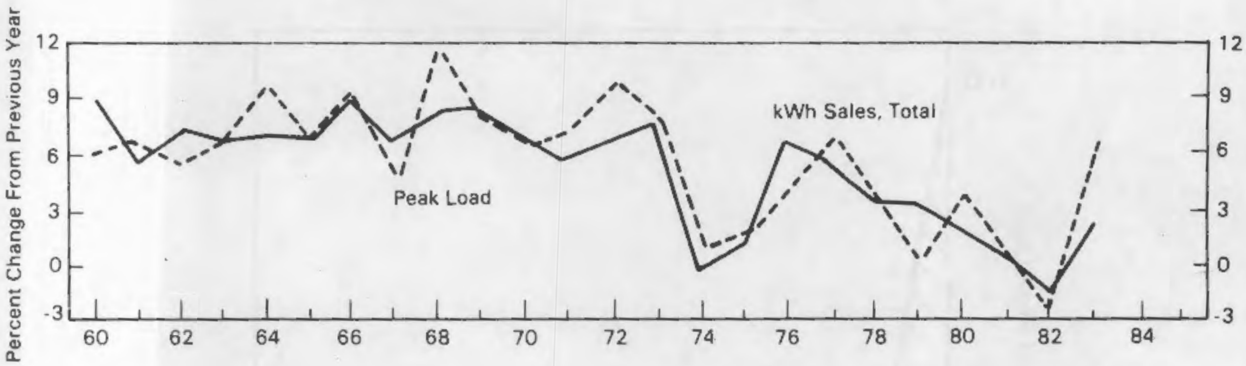


FIGURE 8. Annual National Variations in Peak Load and Energy Sales

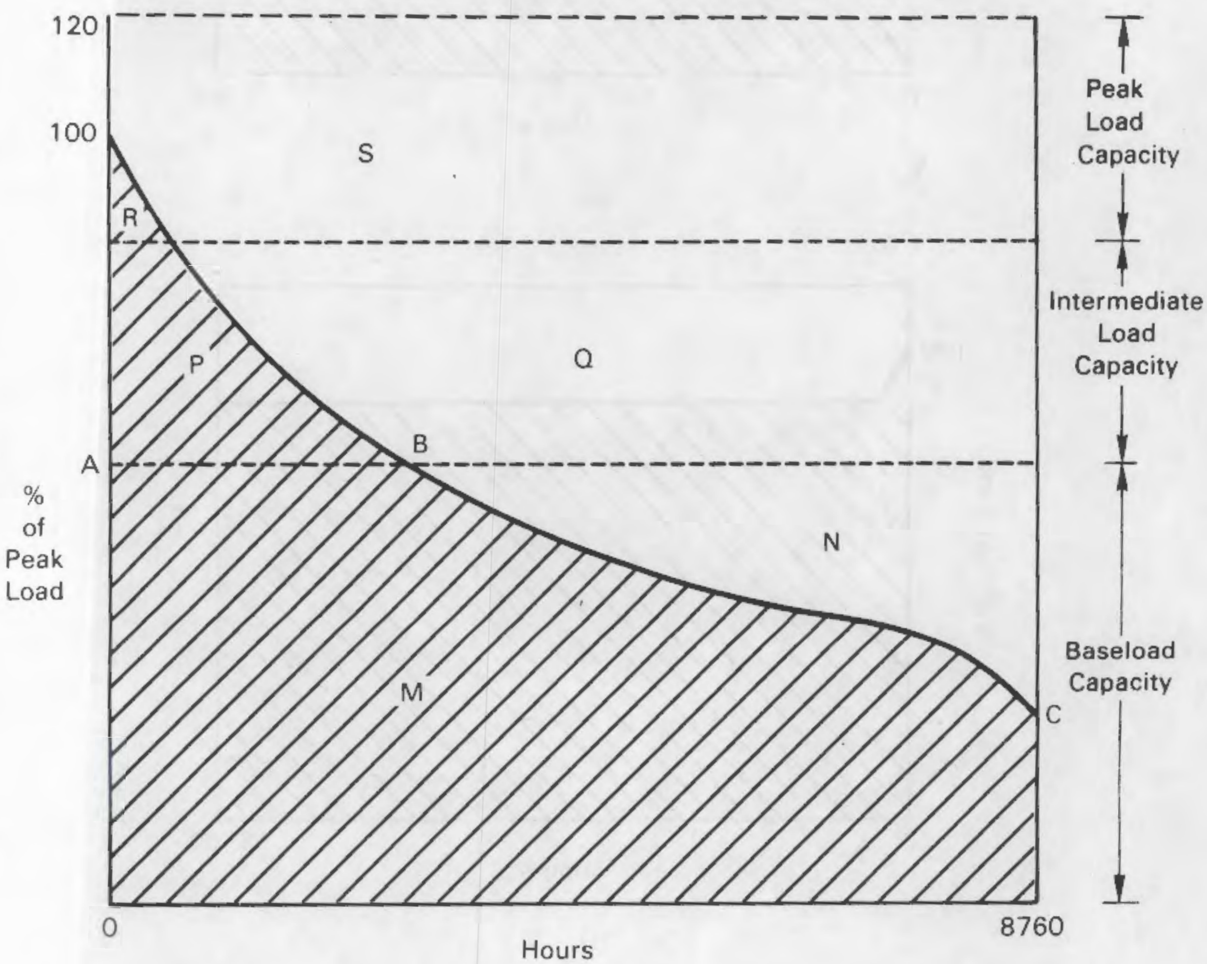
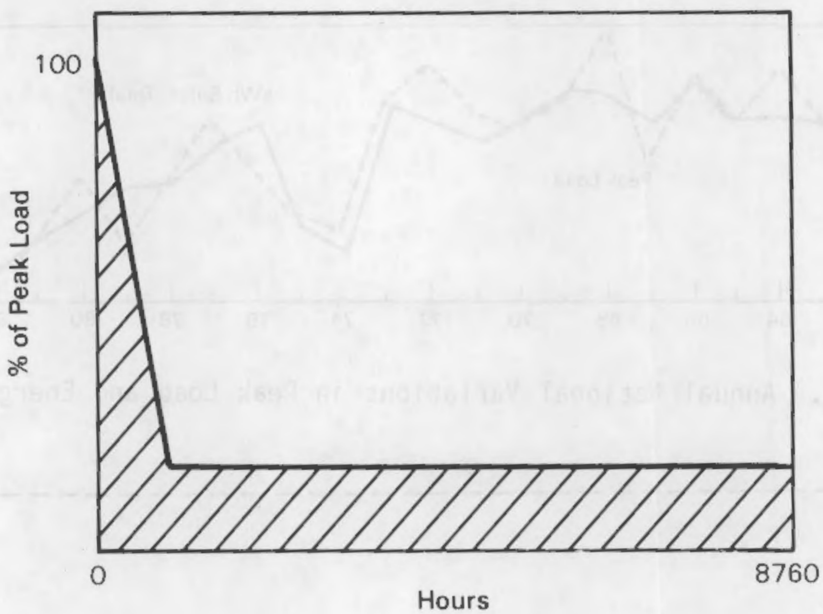
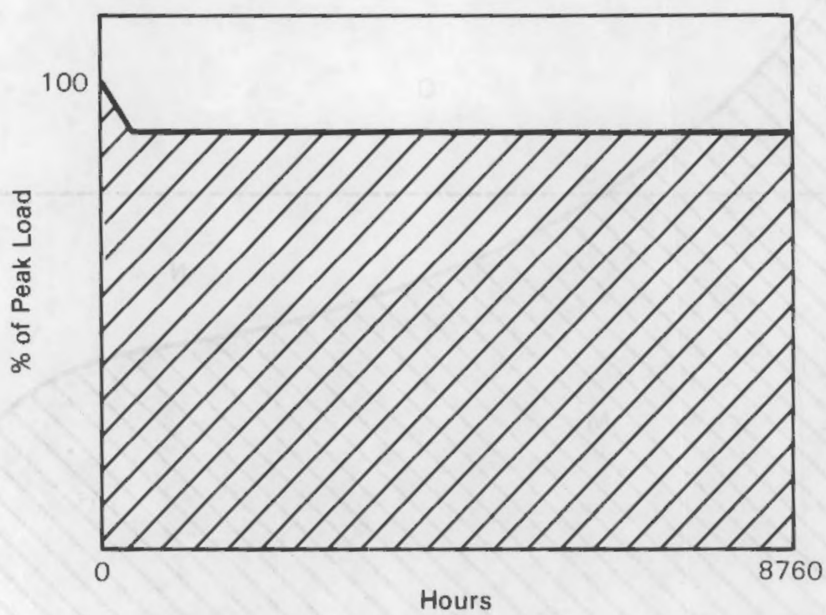


FIGURE 9. Relationship of Typical Load Duration Curve to Generating Capacity

Source: Hyman, L. S. 1985. American Electric Utilities Past, Present, and Future, 2nd ed., p. 50.



a)



b)

FIGURE 10. Hypothetical Example Illustrating Extreme Diversity in Load Duration Curve

Reserve Margin

The reserve margin is the installed capacity above the peak load, expressed in percent, as (Capacity - Peak)/Peak. The margin allows for scheduled outages, forced outages, deratings, and higher than projected peak demands. To meet reliability criteria, 20% is the rule-of-thumb for the reserve margin.[a] Some suggest a target value of about 25% (EW 85, p. 56). A study (EPRI 78, pp. S8-S11) for EPRI indicates that the optimum reserve margin for some utilities may be about 30%. However, the optimum reserve margin for a specific utility system depends on the characteristics of that system. On the other hand, load management, time-of-day pricing, and expanded regional interties may enable utilities to operate with lower reserve margins. The lowest reserve margin, nationwide, since 1953 was 16.6% in 1969 (Hy 85, pp. 85, 103). Reserve margins between 1946 and 1952, however, ranged between 6% and 14% (Hy 85, p. 85). Thus, discounting the low reserve margins in the post World War II years, 15 to 30% probably covers the optimum range for the national reserve margin.

The term "reserve margin" may be a little misleading. A large fraction of the capacity included in the reserve margin is typically unavailable (out-of-service) at the peak load. The "available" reserve capacity at the peak is the critical measure of reliability at the peak load. A recent article on reliability (EPRI 86, p. 10) showed that 15 to 18% of capacity was unavailable at the peak load (Table 2). In 1983, for example, the capacity margin[b] was 25%. However, at the peak 6% of the capacity was down for maintenance, 6% was down for forced outages, and 3% was not available because of partial outages and derating. Thus, 15% of the capacity was unavailable at the peak, leaving an operating margin (available reserve capacity) of 10%. This is illustrated in Figure 11. Note that the percentages shown in Table 2 refer to the capacity margin and not to the reserve margin.

(a) The 20% rule-of-thumb for the reserve margin derives from a report by the Federal Power Commission (FPC), titled "The 1970 National Power Survey." The FPC concluded that a 20% reserve margin industry wide, might be advisable (Senate 85, pp. 1243-1244). This rule-of-thumb value was devised over 15 years ago before the construction of 1000+ MWe power plants.

(b) The capacity margin is expressed in percent as (capacity - peak)/capacity.

TABLE 2. U.S. Capacity and Operating Margins[a]

	1976	1977	1978	1979	1980	1981	1982	1983
Demonstrated U.S. capacity, GW	485	506	531	544	558	572	586	596
Reserve capacity, GW	125	119	135	146	131	144	171	148
Peak demand, GW	360	387	396	398	427	428	415	448
Capacity margin, %	26	24	25	27	23	25	29	25
Maintenance, %	4	4	5	5	5	5	5	6
Forced outages, %	6	7	6	8	7	7	7	6
Partial outages and deratings, %	5	5	6	5	5	5	5	3
Unavailability, %	15	16	17	18	17	17	17	15
Operating Margin, %	11	8	8	9	6	8	12	10

(a) EPRI 86, p. 10.

RETIREMENT OF OBSOLETE CAPACITY

The need for new capacity additions also depends on the retirement of obsolete capacity, which in turn depends on the average service life of the power plants. The average service life of plants retired since 1970 is 36 years. However, service life can often be extended to 40 or 50 years or more. Utilities are currently undertaking plant life extension and upgrading programs that could cost a fraction of the cost for new capacity.

The need for replacement capacity in future years can readily be calculated for various service life assumptions. The variation in capacity retirement schedules for existing U.S. generating plants under different service life assumptions is shown in Table 3. The retirement schedules depend on the capacity installed years earlier. For instance, 31 GW of new capacity was added in 1974. Assuming a 30-year life, this same 31 GW would be retired in 2004. Assuming a 40-year life, this 31 GW would be retired in 2014. Note for the example years, 2004 and 2014, shown in Table 3, how the capacity retired varies with the assumed service life. As noted later, the assumed service life causes some irregularity in capacity projection trends. Historical data on the installed capacity and net capacity additions are provided in Appendix I.

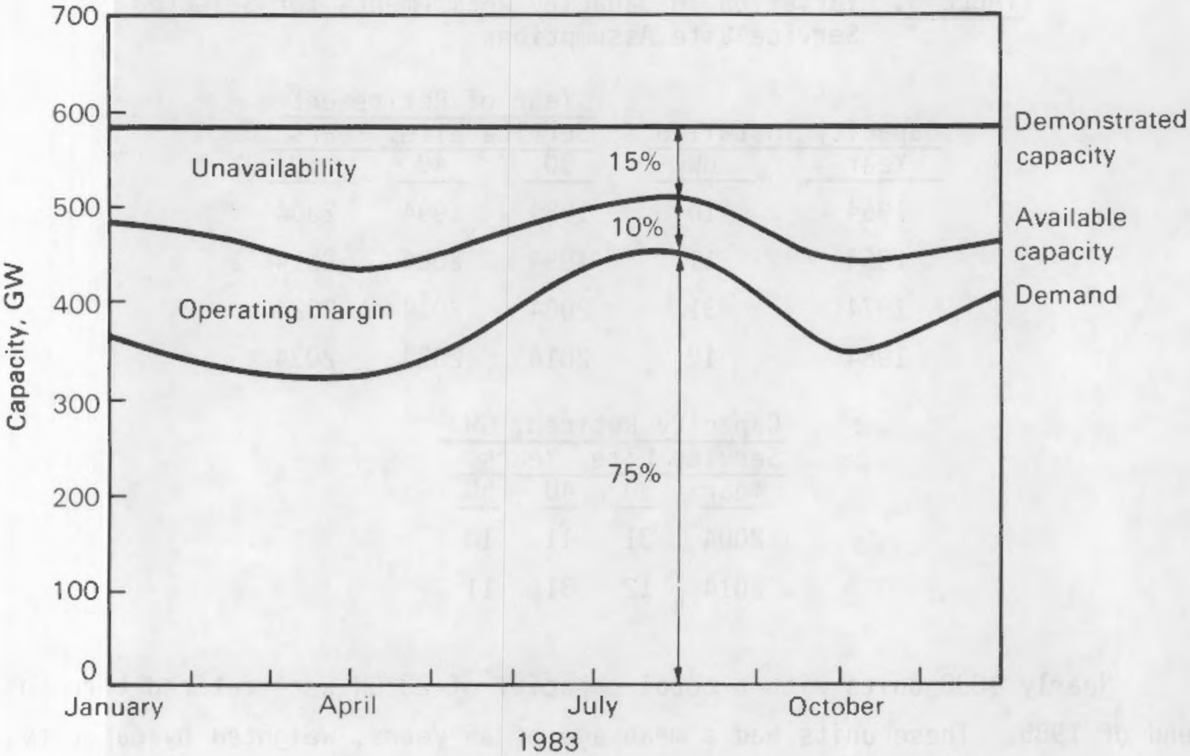


FIGURE 11. Effect of Availability on Margins[(a)]

Note: Providing reliable electric service requires having reserve capacity actually available when needed. A distinction must therefore be made between the theoretical capacity margin usually quoted and the operating margin provided by readily available plants. During 1983, for example, demand for electricity reached only 75% of utilities demonstrated capacity, but 15% of capacity was sometimes unavailable because of preventive maintenance, forced outages, and other causes leaving an actual operating margin as low as 10% during the summer demand peak.

(a) EPRI 86, p. 10.

TABLE 3. Variation in Capacity Retirements for Selected Service Life Assumptions

Capacity Installed		Year of Retirement Service Life, Years		
Year	GW	30	40	50
1954	10	1984	1994	2004
1964	11	1994	2004	2014
1974	31	2004	2014	2024
1984	12	2014	2024	2034

	Capacity Retired, GW Service Life, Years		
Year	30	40	50
2004	31	11	10
2014	12	31	11

Nearly 1800 units with a total capacity of 23 GW were retired through the end of 1985. These units had a mean age of 36 years, weighted by capacity. An additional 400 units with a capacity of 5.3 GW have also been retired, but the startup and/or retirement dates for these units were unknown. The average capacity of the retired units was 13 MW. The largest unit retired to date was 200 MW. About 800 steam-electric units comprised most (19 GW) of the retired capacity. The average age at retirement was 38 years, weighted by capacity, for the steam electric units. Most of the retired capacity (13.1 GW) had been fueled by oil and gas. Only 200 MW in over 100 small hydro units were retired; their average age was 54 years. The average age of the retired units has remained nearly constant over the past 15 years. Planned retirements by utilities to the year 2000 are 17 GW with an average age of 37 years. The characteristics of the retired plants are summarized in Appendix D.

The recent retirement schedule, i.e., 1981-1985, is consistent with replacing 35- to 40-year old plants (Table E.4). However, the planned retirement schedule, through 1995, is more consistent with replacing 50 year old plants. Although the average age of the units to be retired through 1995 is projected to be 36 years, the rate of retirements is less than the installation rate of new capacity 36 years earlier. Thus, the planned retirement schedule, if it holds, reflects overall aging and is consistent with plant life extension programs. The average age of installed capacity would reach 30 years in 1995, up from 24 years currently.

NERC FORECASTS TO 1994

The NERC annually forecasts annual demand, peak demand, and capacity for the next 10 years. The forecast is an aggregation of individual utility system forecasts. NERC represents virtually all of the power systems in the United States and Canada.

The 1985 NERC forecast (NERC 85) is for an average annual growth in the summer peak demand and electricity consumption of 2.3% and an average annual growth in generating capacity of 1.7% (Table 4). The reserve margin at the summer peak demand was 34% in 1984, and is projected to decrease to 26% in 1994. After 1995, when the current excess capacity has been reduced to normal levels, new generating capacity will be needed at a rate to keep pace with the growth in peak demand. NERC projects the U.S. peak demand to be 567 GW in 1994. The U.S. capacity at the peak is projected to be 712 GW in 1994.

In the period from 1985 to 1994, 125 GW of new capacity and 17 GW in retirements are planned for a net addition of 108 GW. Of the 108 GW, increase coal capacity is forecast to increase by 50 GW and nuclear capacity is forecast to increase by 50 GW. Planned retirements are concentrated in units using petroleum (7 GW) and gas (7 GW) (DOE 85c, p. 54).

TABLE 4. NERC Forecasts for Selected Years

	1984 Actual	Forecasts 1985	1990	1994	Average Annual Increase 1984-1994, %
Peak demand, GW	451	465	520	567	2.3
Electricity Requirements, Billions of kWh	2,446	2,499	2,816	3,081	2.3
Summer capability, GW	604	617	676	712	1.7
Reserve Margin, %	34	33	30	26	

LONG-TERM PROJECTIONS TO 2035

Over the long-term, electricity demand is expected to track the economy. The economy, as measured by real GNP, has typically grown at the rate of 2 to 4% per year with the long-term average near 3%. Real GNP should continue to grow in response to increased population and productivity.

We have projected the peak demand to the year 2035, assuming growth rates of 1.5, 2.5, and 3.5% (Table 5). The base year is 1984. Using NERC's forecasted installed capacity in 1994 of 712 GW (from Table 4), the projected reserve margin in 1995 ranges from 181 GW (34%) at the 1.5% growth rate to 53 GW (8%) at the 3.5% growth rate. The projected reserve margin is 130 GW (22%) at the 2.5% growth rate. The growth rate assumption is obviously critical to the projected peak demand and the need for new capacity; the peak demand is 300 GW higher in 2005 at the 3.5% growth rate than at 1.5%.

Scenarios for Estimating Long-Term Capacity Needs

Three scenarios were developed to study the range of probable demands for new capacity. The scenarios vary the peak demand growth rate, the reserve margin, and the retirement schedule since these factors determine the need for new generating capacity. The middle scenario reflects our view of the most likely scenario. The high and low scenarios, which combine the worst case values in each direction, reflect our view of the most likely extreme or boundary conditions. As noted before, the reserve margin applies to the peak

TABLE 5. Projected Peak Demand to 2035

Assumed Growth Rate	(GW) 1995	2005	2015	2025	2035
1.5%	531	617	716	831	964
2.5%	592	758	970	1242	1589
3.5%	659	929	1311	1849	2608

demand. The baseload demand and the need for baseload capacity are not affected by the reserve margin. The three scenarios are as follows:

- High-Demand Scenario

Peak Demand Growth	3.5% per year
Reserve Margin	25%
Average Service Life	30 years

- Middle-Demand Scenario

Peak Demand Growth	2.5% per year
Reserve Margin	20%
Average Service Life	40 years

- Low-Demand Scenario

Peak Demand Growth	1.5% per year
Reserve Margin	15%
Average Service Life	50 years

Total Capacity Requirements

The capacity requirements for each of these scenarios were calculated out to the year 2035 (Table 6; see Appendix J for the complete year-by-year tabulation). By 1995, the difference between the high and low scenarios will grow to 150 GW. The planned capacity in 1994 by NERC is 712 GW. This capacity is required in 1991 for the high scenario, in 1994 for the middle, and not until 2004 for the low scenario (Table 7). Under the high scenario, construction would need to be accelerated for plants now under construction, and new

TABLE 6. Capacity Requirements (GW)

Scenario	1984[a]	1995	2005	2015	2025	2035
High Demand	604	823	1161	1638	2311	3260
Middle Demand	604	720	909	1164	1490	1907
Low Demand	604	674	716	823	955	1109

(a) Actual capacity.

TABLE 7. Year in Which Currently Planned Capacity Required[a]

Scenario	Year
High Demand	1991
Middle Demand	1994
Low Demand	2004

(a) The currently planned capacity is 712 GW in 1994.

capacity commitments would need to be made soon[a] for the post-1991 operation. The middle scenario corresponds closely to current capacity expansion plans. Under the low scenario, current capacity expansion plans would need to be stretched out about 10 years.

The incremental capacity additions to meet projected load growth for each scenario over the 712 GW currently planned for 1994 are summarized in Table 8. For the middle scenario, an additional 197 GW are required by 2005. For the

TABLE 8. Incremental[a] Capacity Requirements (GW)

Scenario	1995	2005	2015	2025	2035
High Demand	111	449	926	1599	2548
Middle Demand	8	197	452	778	1195
Low Demand	(38)[b]	4	111	243	397

(a) Incremental to 712 GW already planned for 1994.
(b) Parentheses indicate negative value.

(a) Since new baseload capacity requires a lead time of eight to ten years, additional capacity requirements prior to 1995 would have to be smaller units, such as gas turbines, that could be installed when needed. Other possibilities for the near term are upgrades of existing plants, power purchases, and phase-ins of combined cycle plants. The recent growth rate has been about in line with the middle scenario, indicating that a pick up in the orders for new baseload capacity should occur within the next two years.

high scenario, an additional 449 GW are required by 2005. For the low scenario, only 4 GW more are required by 2005, but an additional 111 GW is required by 2015.

The total new capacity requirements to meet both load growth and the need to replace plants are obtained by adding the retirements to the incremental capacity requirements shown in Table 8. The retirements of obsolete capacity, after the planned capacity of 712 GW is reached for each scenario, are shown in Table 9. Recall that the retirements are based on the average service life (30, 40, or 50 years) assumed for the high, middle, and low demand scenarios, respectively. The table illustrates the potential effect of extending plant life on the need for new capacity; that is, if a 50-year life is assumed for the high demand scenario, the cumulative retirements to 2035 would be 519 GW, the same as the low demand scenario. The total new capacity requirements (Table 10) are obtained by adding Tables 8 and 9.

The need for new baseload capacity (Table 11) is estimated to be about 60% of the total new capacity requirements (see footnote p. 34). The need for new baseload capacity determines the potential need for new nuclear or coal plants. The cumulative need for new baseload capacity to year 2035, over and above the

TABLE 9. Cumulative Retirement of Obsolete Capacity (GW)

Scenario	1995	2005	2015	2025	2035
High Demand	50	295	455	661	999
Middle Demand	11	120	365	525	628
Low Demand	0	11	120	365	519

TABLE 10. Cumulative Need for New Capacity[a] (GW) for Both Load Growth and Replacement of Obsolete Capacity

Scenario	1995	2005	2015	2025	2035
High Demand	161	744	1381	2266	3547
Middle Demand	19	317	817	1303	1823
Low Demand	0	15	231	608	916

(a) Above the currently planned capacity of 712 GW.

TABLE 11. Cumulative Need for New Baseload Capacity (GW)

Scenario	1995	2005	2015	2025	2035
High Demand	93	429	795	1302	2043
Middle Demand	11	190	490	782	1094
Low Demand	0	9	145	381	574

712 GW capacity already included in NERC plans through 1994, ranges from 574 GW in the low scenario to 1094 GW in the middle scenario to 2043 GW in the high scenario.The need for new (in addition to currently scheduled) baseload capacity occurs in 1992 under the high scenario, in 1995 for the middle scenario, and in 2005 for the low scenario.

ANNUAL REQUIREMENTS FOR NEW CAPACITY

Turn now to the annual requirements for new capacity to meet load growth, retirements, and reserve margins. For perspective, consider the steep decline in the annual additions to capacity and the prospects for recovery (Table 12). The largest additions to capacity, 44 GW, occurred in 1973. Since then there has been a general decline. The decline, using NERC 1986 projections,[a] is forecast to bottom out in 1990 at 4 GW, a slow pickup to 9 GW in 1995 is projected. Under the middle demand scenario (Table 12), the annual additions to capacity, above those projected by NERC, would increase rapidly to 31 GW in 1998. However, the retirements under the 40-year service life assumed in the middle demand scenario are much higher than the retirements planned for the 10 preceding years. Thus, if longer service lives did prevail and plant retirements were lower, the annual capacity additions would be smaller than shown. Nonetheless, annual capacity additions would increase to over 20 GW by the year 2000.

The annual requirements for the three scenarios are summarized for selected years in Table 13. For example, 67 GW of new capacity are required in the year 2005 under the high demand scenario. Keep in mind that approximately

(a) The 1986 projections used here became available after the preceding analysis was complete. The preceding analysis used the NERC 1985 projections.

TABLE 12. Annual Additions to U.S. Generating Capacity (GW)

EIA Historic Data (1973 - 1984)

Year	Annual Additions	Retirements	Net Additions
1973	44	1	43
1974	37	1	36
1975	31	1	30
1976	24	1	23
1977	30	1	29
1978	20	1	19
1979	20	1	19
1980	17	1	16
1981	24	3	21
1982	18	3	15
1983	11	3	8
1984	17	3	14
1985[b]	26	2	24
NERC 1986 Projections (1986 - 1995)			
1986	16	1	15
1987	17	1	16
1988	10	1	9
1989	4	1	3
1990	4	1	3
1991	8	1	7
1992	7	2	5
1993	5	2	3
1994	7	1	6
1995	9	1	8
Middle Scenario (1996 - 2000)			
1996	14[a]	6	8
1997	26	7	19
1998	31	12	19
1999	32	13	19
2000	30	10	20

(a) An additional 10 GW over the NERC projections would be required in 1995 under the middle demand scenario to replace retired plants that were originally brought online in 1955.

(b) Based on preliminary EIA data for 1985.

TABLE 13. Annual New Capacity Requirements[a] (GW)

Scenario	1995	2005	2015	2025	2035
High Demand	40	67	68	106	150
Middle Demand	19	35	56	49	55
Low Demand	3	15	25	42	23

(a) For growth and replacement of retired plants.

67 GW are also required in 2006, 2007, etc., since these are annual requirements. The annual requirements are somewhat erratic in that the retirements in a given year reflect historical plant additions. For instance, the peaks in 2015 and 2025 for the middle and low scenarios, respectively, are caused by replacing plants that began service in 1975 according to the assumed 40- and 50-year retirement schedules, respectively, for these scenarios. Plant additions in 1975 were unusually high compared to additions in 1965 and 1985. The total new capacity requirements include the need for peaking capacity, load-following capacity, and baseload capacity.

We estimate the annual need for new baseload capacity (Table 14) to be approximately 60%[a] of the total new capacity requirements previously shown in Table 13. The annual need for new baseload capacity is used below to arrive at an estimate of the maximum plant size that would be needed on a regional basis.

Regional Capacity Needs

There is a potential demand for new large baseload units or multiple small units in all NERC regions under all scenarios. We estimated the need for new baseload capacity in each NERC region (Table 15) for the middle demand scenario by distributing the total national demand. The distribution was prorated based

(a) Assume that the shape of the load duration curve remains constant; i.e., that the baseload grows proportionally to the peak demand. With a 20% reserve margin, assume 60% of new capacity is baseload. Adjust the 60% slightly for the higher and lower reserve margins since the reserve margin does not change the shape of the load duration curve.

TABLE 14. Annual Need for New Baseload Capacity (GW) in Selected Years[a]

Scenario	1995	2005	2015	2025	2035
High Demand	23	39	39	61	86
Middle Demand	12	21	34	30	33
Low Demand	2	9	16	26	14

(a) For load growth and replacement of retired plants and assuming baseload capacity is 0.72 times peak demand.

TABLE 15. Annual Need (MWe) for New Baseload Capacity by NERC Region for the Middle Demand Scenario

NERC Region[a]	1995	2005	2015
ECAR	1,700	3,000	4,900
ERCOT	1,100	2,000	3,200
MAAC	800	1,500	2,400
MAIN	800	1,500	2,400
MAPP-US	600	1,000	1,600
NPCC-US	1,000	1,700	2,700
SERC	2,600	4,600	7,400
SPC	1,200	2,200	3,000
WSCC	2,100	3,700	6,000
NERC-US TOTAL	12,000	21,000	34,000

(a) See Appendix H (p. H.1) for NERC Region Explanations.

on projected summer peaks in 1994.[a] Under the middle scenario, there is a need in 1995 for large baseload capacity in each region, beyond that already planned. The need, of course, is even greater and sooner for the high scenario. Under the low scenario, new capacity, beyond that already planned, is not required until 2005, but a potential need for new large baseload units occurs in each region at that time. The need can be met by either large single units or multiple small units.

Planning Uncertainties

The differences in capacity requirements between the high and low scenarios are enormous. Translated into dollars, the differences reach into the hundreds of billions. The high and low scenarios, we believe, bound the range of future capacity demands and illustrate the magnitude of the uncertainties facing capacity planners. Fortunately, planning horizons are shorter and plans can be adjusted as events unfold. But, as we have seen, adjustments to abrupt changes in demand, such as occurred in 1973, can take a long time.

Planning uncertainties deal with demand projections and what drives them. Apparent drivers are GNP, price elasticity, and inter-fuel competition. Underneath lies a web of complex relationships, constantly changing with economic and social activity.

One of the obvious factors that affects uncertainty is the length of the lead time between the capacity addition decisions and plant startup. The rate of divergence (2% per year) between the low and high projections provides a measure of the relationship of uncertainty to lead time. For instance, for each year the lead time is shortened or lengthened, the uncertainty in the capacity requirements for a future target year is reduced or increased, respectively, about two percent, or about 14 GW currently.

(a) This distribution assumes that post-1994 regional growth rates would correspond to the national average (2.5%) and that plant retirements could also be prorated on the same basis. In Table 1 the projected regional growth rates to 1994 varied from 1.1 to 3.6% per year for the peak load. This range nearly corresponds to the growth rates for the three scenarios. Our purpose is to point out that a potential should exist for large plants in all or nearly all regions by 2005, especially if the needs for two consecutive years can be combined.

SUPPLY OPTIONS

SUMMARY

Nearly all (95%) of the electricity generated in 1985 came from coal (56.8%), nuclear (15.5%), hydro (11.4%), and natural gas (11.7%). The remaining 5% came from petroleum (3.7%) and other sources (1.1%). In 1984, 4366 active power plants generated electricity, but 90% of the electricity produced was generated by only 12% of the plants.

During the next decade, about 100 GW of new baseload capacity and 20 GW of other capacity is scheduled to be added. Most of this new baseload capacity will be comprised of either coal or nuclear plants. By 1994 the installed capacity represented by nuclear plants will have increased to 16% from 10% in 1984. If additional capacity is required, beyond that currently planned, it will most likely consist of small blocks of peaking capacity that can be brought on-line quickly (e.g., gas turbines).

It is expected that for several decades beyond the mid-1990s, electricity supply will continue to come from many sources, but that the primary sources will continue to be baseload coal and nuclear plants. Only coal and nuclear have the extensive domestic fuel reserves and proven technology to reliably provide large blocks of power at low costs. While the relative contribution of hydro and petroleum is expected to decrease, the contribution of alternative energy sources is expected to increase.

EXISTING CAPACITY AND GENERATION

At the end of 1985 there were 10,904 generating units with a total nameplate capacity of 696 GW[a] in the United States. Their sizes ranged from 10 KW to 1372 MWe or 6 orders of magnitude (Table D.1). In general, most of the older units were smaller and were installed originally to meet local demands. The newer units were generally larger and were installed to meet regional demands. The age and size distribution is summarized in tables D2-D6 in Appendix D.

The large units typically provide baseload capacity, and smaller units usually provide intermediate and peak load capacity. The large units take advantage of economies of scale in design and operation and have the lowest unit electrical generation cost when operated at high capacity factors. Peaking units, on the other hand, are able to startup quickly and usually have the lowest cost at low capacity factors. Many older units, originally operated as baseload units, are converted to intermediate or peak load operation when their variable (operating and fuel) costs exceed those of new baseload units. The boundaries between peak load, load-following, and baseload are not clear-cut. Rather, the units in a system represent a continuum with the operation of each unit selected to minimize total generation cost while reliably meeting the total demand.

In 1984, 4366 "active" power plants generated electricity out of a total of 5692 "active" and inactive power plants. A power plant consists of one or more generating units. For example, Wanapum Dam, a power plant of 831 MW, consists of ten 83.1 MW units (turbine/generators). However, 24% of the electricity was generated by only 46 (1%) power plants that, on average, generated

(a) This is the EIA 1985 year-end capacity based on a data tape available in February 1986. The 1984 NERC capacity of 604 GW, used previously, is based on summer ratings at the summer peak. The NERC summer capacity figure is about 10 percent below the year end nameplate capacity reported by the EIA. In 1984, EIA reported a year-end capacity of 672 GW. Several factors account for the difference. EIA includes Alaska, Hawaii, and Puerto Rico. NERC includes virtually all power systems in the contiguous states only. The NERC capacity is based on the derated capacity, partly due to higher summertime temperatures of the cooling water, rather than the nameplate capacity. EIA includes capacity added after the summer peak.

over 10 billion kWh each (Table 16). Over half of the electricity was generated by 4% (158) of the active power plants, and 90% of the electricity was generated by only 12% of the active power plants. Thus, based on percentage, comparatively few power plants generate nearly all of the electricity. Conversely, 88% of the active plants generated only 10% of the electricity.[a] The rows in Table 16 were based on power plants generating over 10, 5, 3, and 1 billion kWh in 1984. Keep in mind that over 1300 plants were inactive in 1984.

In 1985 (NERC 86), coal-fired units had the largest capacity (272 GW), followed by dual (oil/gas) (87 GW), nuclear (71 GW), conventional hydro (70 GW), oil (60 GW), gas (44 GW), and other (17 GW) (Figure 12). Other includes pumped storage, geothermal, solar, refuse, and wood. By energy generation (Figure 13), coal ranked first (57%), followed by nuclear (16%), natural gas (12%), conventional hydro (11%), oil (4%), and other (1%). (Totals add to 101% due to rounding.) The capacity data represents the summer capability.

The current situation is one of surplus capacity. From 1985 through 1995, 87 GW of new capacity is scheduled to be added. Most of this new capacity is

TABLE 16. Power Generation in 1984 by Type of Power Plant

Cumulative Generation (%)	Cumulative Percentage of Plants (%)	Generation Per Plant[a]	Cumulative Number of Plants: Total	Coal	Nuclear	Hydro	Natural Gas	Fuel Oil	Geothermal
24	1	>10	46	30	10	4	2	--	--
56	4	>5	158	99	34	10	11	3	1
71	6	>3	258	165	47	16	24	5	1
90	12	>1	511	292	60	41	84	33	1

(a) Billions of kWh.

(a) Based on information contained in computerized data base of United States Power plants compiled by DOE, Energy Information Administration, February 1986.

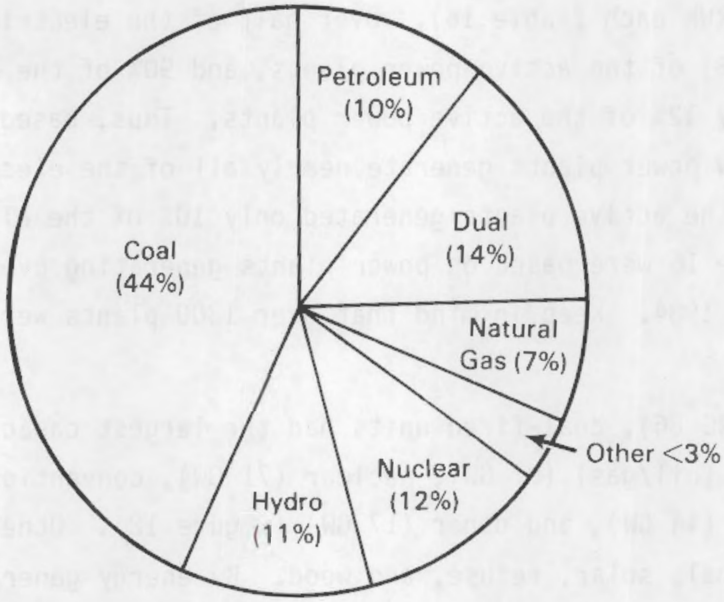


FIGURE 12. Generating Capacity by Fuel Type (1985)

Note: Dual uses either natural gas or petroleum.

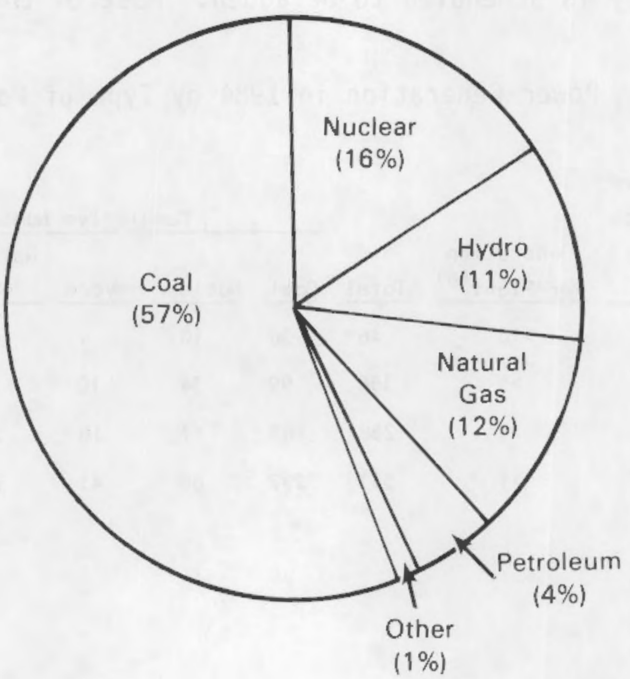


FIGURE 13. Electricity Generation by Fuel Type (1985)

Note: Totals equal 101% due to rounding.

comprised of coal (31 GW) and nuclear (30 GW) plants. Nearly all of the new capacity is currently under construction. Should additional capacity be required, smaller blocks of peaking capacity, such as gas turbines, would be brought in quickly, perhaps as part of a staged-construction, combined-cycle plant (ED 86, p. 1).

Conservation has not played as important a role in electricity usage as in overall energy usage. A crude measure of conservation is the productivity of electricity as measured by the ratio of real GNP to electricity generation. There has been only a slight increase (3%) in this ratio over the last decade. In contrast, the ratio of real GNP to overall energy consumption has increased about 30% over the same period (Hy 85, p. 101). The slight increase in electricity productivity could be caused by shifts in the economy away from electricity consuming industries. However, decreases in electricity consumption per unit of output did occur in the top four electricity intensive industries, chemicals, paper, primary metals, and food processing. Conservation was also important in the residential and commercial sectors. Over the last four years electricity demand in these sectors declined although the sectors grew at a faster rate than GNP (DOE 85b, pp. 21-39).

FUTURE SUPPLY OPTIONS

The future electricity supply is expected to come from many sources, but only coal and nuclear currently have the extensive domestic reserves and proven technology to reliably provide large blocks of low cost power. Therefore, under present conditions the future electricity supply is expected to be generated primarily by coal and nuclear baseload plants and existing large hydroelectric plants. Baseload plants are expected to comprise about 60% of future capacity and produce about 80% of the electricity. The remaining 40% of capacity is expected to be load-following, non-firm, and peak load plants. Hydroelectric, natural gas, oil, solar (wind, photovolatics, solar-thermal, biomass, etc.), coal, geothermal, and cogeneration are expected to provide most of this capacity and will produce about 20% of the electricity. Canadian imports are expected to increase and become an important supply, particularly in the Northeast. In 20 to 40 years, breakthroughs in fusion and breeder reactors could lead to the commercialization of these technologies. Since new developments frequently alter the competitive situation, pursuing diverse energy options is advantageous and avoids dependency on a single option.

RESOURCE CONSUMPTION AND WASTE PRODUCT GENERATION

SUMMARY

This section estimates the resource consumption and waste generation for the coal and nuclear fuel cycles for three scenarios. One scenario assumes the phasing out of nuclear and its replacement with coal over the long-term. The opposite scenario assumes the phasing out of coal and its replacement with nuclear. The middle scenario assumes a 50/50 split in new baseload capacity between coal and nuclear. These scenarios cover the extreme ranges of coal and nuclear usage expected over the long-term. The 50/50 split corresponds to recent experience and planned construction through 1994.

Even under the extreme scenarios, domestic coal and domestic uranium resources are sufficient to meet the projected demand. However, exclusive use of domestic resources does result in a significant depletion of those reserves by 2035:

PERCENT OF DOMESTIC RESOURCES CONSUMED THROUGH 2035

	Supply Scenario		
Resource	All Coal	All Nuclear	50% Coal, 50% Nuclear
Coal[a]	25	8	16
Nuclear[b]	9	56	33

(a) Based on estimated recoverable coal reserves of 245 billion tons.
(b) Based on estimated total recoverable U_3O_8 of 7.07 million tons.

No supply problems will necessarily occur in any part of either fuel cycle because the required growth rates are low and lead time for capacity expansion of critical fuel cycle services are exceeded by the lead times required for power plant construction. Under the all-nuclear scenario, demand will equal

the current United States uranium enrichment capacity (including a non-operating facility currently on "standby") in about 2005. Under the 50% nuclear scenario, demand is projected to equal enrichment capacity in 2015.

The fuel requirements and waste generation from coal plants are huge compared to nuclear. These requirements make coal generation more susceptible to future supply disruption (in mining and transportation) and inflation than nuclear. Low-cost technology is available to handle the coal supply and waste generation under existing regulations. However, changes in these regulations in response to environmental concerns could lead to restrictions on coal usage and large cost increases.

INTRODUCTION

Previous sections of this report clearly identify the need for new base-load electricity generation plants, beyond those already scheduled, before the year 2000. Based on current experience, coal and nuclear technologies are unique in their proven ability to provide low cost electricity using domestic fuel reserves and in their potential for significantly increased utilization. It is apparent that both technologies will play a role in the future; however, the relative roles of the two technologies is subject to questions.

Aside from meeting the pure demand requirements, other factors influence decisions on the relative roles of nuclear vs. coal technologies. These factors include economics, reliability of the fuel supply, waste product generation and disposal, environmental and health concerns, and public acceptability.

The purpose of this section is to assess the requirements for critical resources and to estimate the quantities of wastes generated for future supply scenarios involving various mixes of coal and nuclear plants. Projections of resource requirements and of impacts in terms of waste generated provides a perspective for formulating long range research and development plans to improve technology, mitigate adverse impacts, assure the availability of critical resources, and to increase the utilization of potential by-products.

Comparisons in fuel requirements, transportation and processing needs, and waste generation and disposal are made for three scenarios that assume that most new baseload power plants are: 1) all coal, 2) all nuclear, and 3) 50% coal, 50% nuclear. The assessments are based on utilization of existing technologies.

Two important effects, health and safety, are beyond the scope of this analysis. Legislation and regulations prescribe the acceptable levels of risk to society for a technology. The acceptable levels of risk attempt to strike a proper balance between the benefits and costs to society. The ALARA, "as low as reasonably achievable," principle applied to radiation protection reflects society's desire for a proper balance, for example.

Past work on health and safety risks of the coal and nuclear fuel cycles are not conclusive. In a May 1984 study (Fi 84) Sandia National Laboratories evaluated the literature on coal and nuclear fuel cycle risk comparisons. They concluded that 1) the inadequacies in existing analyses could be removed with better data on health effects of the coal fuel cycle, 2) more appropriate metrics were needed to compare the coal and nuclear fuel cycles, 3) health effects models for the coal fuel cycle were simplistic compared to those for the nuclear fuel cycle, 4) the lack of rigor among analysts in precisely defining the aspect of the fuel cycle being addressed made comparisons difficult, 5) the credibility and acceptability of existing comparisons was questionable, and 6) additional work was required in the areas of socioeconomic and sociopolitical impacts assessment to obtain more creditable/acceptable risk comparisons.

ASSUMPTIONS USED IN THE SCENARIOS

We assumed that the proportion of coal plus nuclear generation to the total generation in 1984 would remain constant. In 1984, 68% of the total electricity generation was coal plus nuclear.[a] We assumed that the generation would grow at the rate of 2.5% per year. We assumed that the

(a) By implication we assume that 32 percent of the future electricity generation will come from other fuels. We expect those to be hydro, natural gas, oil, geothermal, solar, etc. Current trends point to a decline in the percentage of hydro, natural gas, and oil. If the trends continue, this assumption would imply substantial growth in the alternative generation technologies.

nuclear plants under construction would be completed by 1994 according to NERC plans. We further assumed that the nuclear plants would increase their average capacity factor from 60% in 1984 to 65% in the year 2000. For simplicity, all steps of each fuel cycle were assumed to occur in the same year as power production.

In the all-coal scenario, no new nuclear plants are ordered. The coal generation is calculated by subtracting the nuclear generation from the total coal plus nuclear generation. The nuclear plants are retired 40-years after startup; nuclear generation reaches zero in 2035.

In the all-nuclear scenario, coal generation is calculated in 1994 as above. This generation is reduced to zero in 2035 in proportion to the generation capacity retired, assuming a 40-year plant life. The nuclear generation is then obtained by difference.

The impacts of the half-coal/half-nuclear scenario were estimated to be midway between the all-coal and all-nuclear scenarios.

DESCRIPTION OF COAL AND NUCLEAR FUEL CYCLES

A brief description of the steps in each fuel cycle is presented below. The assumed values are representative of current technology for each fuel cycle.

Coal Fuel Cycle

Coal is produced from underground and surface mines. Most of the underground production (65%) is in the eastern United States (NCA 85, p. 30). The western mines which produced 35% are primarily surface mines. Most reserves are in the West; the proportions of production in the West should gradually increase. Eastern coal is generally higher in sulfur content and heating value than western coal. Underground mining is mostly room and pillar with some long wall mining.

Coal varies widely in properties important to its use as a utility fuel. The sulfur content may range from 0.6 to 6.0%. The ash content usually ranges from 8 to 12%, although much higher values are possible. The heating values range from 6,000 Btu/lb for lignite to 14,000 Btu/lb for bituminous. As mined, coal is diluted with additional impurities. Coal preparation plants, located near the mine, remove most of the mine waste. Mine waste can range from negligible amounts to 30% or more. The coal composition and utilization assumptions used in this study are summarized in Table 17.

After mining, the coal is sorted, cleaned, and sized. The mine waste is dumped in waste embankments. Some is returned to the mine for back fills. The waste frequently contains a large fraction of low-grade coal and other carbonaceous material. Disposal practices must guard against potential combustion and structural instability of the embankments. Coal handling near the mine is usually by truck or conveyor.

After cleaning, the coal is transported to the power plant. Several methods are used: unit trains, mixed trains, barges, trucks, and slurry pipelines. Train haulage is most common. Coal haulage by barge, truck, conveyor, and slurry pipeline make up the 36% not hauled by rail. Barging is generally the lowest cost if access to waterways is convenient. Trucks are used for short haulage. Only a few slurry pipelines have been built and operated.

At the power plant, the coal is stored in stock piles. Nominally, a 60-day supply is maintained as a precaution against supply disruptions.

The combustion of coal produces fly ash, bottom ash, SO_2, NO_x, and CO_2. Fly ash is collected by filters and electrostatic precipitators; bottom ash collects at the bottom of the furnace. SO_2 is removed by flue gas desulfurization (FGD) processes, and in the future, by fluidized bed combustion techniques. The NO_x emissions are reduced by scrubbing and control of the combustion conditions. CO_2 emissions are not controlled.

Ash and sludge from the FGD process are disposed of in land fills, although some is utilized in by-products.

With present technology and emission standards, coal plants are roughly equal to nuclear plants on a unit cost of power basis. Coal plants cost less to build but require higher fuel costs than nuclear plants. Electricity from coal plants is thus more susceptible to future escalation of fuel costs than nuclear plants.

TABLE 17. Assumptions Used in Coal Fuel Cycle Analysis

Composition

Heating value of as-burned coal: 21,000,000 Btu/ton, 10,500 Btu/lb
8,500 Btu/kWh (heat rate)

Sulfur Content: 2.0%

Ash Content: 10.0%

Mine Waste: 16.0%

Mine Waste Properties[(a)]

Dry Density = 90 ft^3
Wet Density = 106 ft^3
Specific Gravity = 1.95

Sludge from Coal Preparation Plants[(b)]

Dry Density = 54 ft^3
Wet Density = 78 ft^3
Specific Gravity = 1.36 to 1.66

Coal Transport

90 tons coal/carload
100 cars/train; total length - 5,500 feet
Average speed = 10 miles/hour
Average distance = 1,800 miles round trip
Fraction hauled by rail = 64%
Coal car utilization = 2,160 hours per year
(hauling coal and returning)

Power Plant Waste Products (EPRI 84, pp. 3-50 to 3-53)

Solid Waste
Total ash = Coal consumption x 0.10
Total fly ash = Total ash x 0.8
Fly ash collected in precipitator = Total fly ash x 0.9
Total bottom ash = Total ash - Total fly ash

(a) Wi 75, p. 398
(b) Wi 75, p. 400

TABLE 17. (contd)

Power Plant Waste Products (contd)

A Fly ash collected in scrubber = Total fly ash x (0.997 - 0.900)

B Weight of $CaSO_4 \cdot 2H_2O$ = Coal consumption x % S x 0.9 x 0.2 x $\frac{172}{32}$

C Weight of $CaSO_4 \cdot 1/2H_2O$ = Coal consumption x % S x 0.9 x 0.8 x $\frac{129}{32}$

D Weight excess reagents as $CaCO_3$ =

Coal consumption x % S x 0.9 x $\frac{100}{32}$ x 0.2

Total solids weight = A + B + C + D

Weight of water = $\frac{40}{60}$ x Total solids weight

Total weight of sludge = $\frac{100}{60}$ x Total solids weight

Bulk Density

Fly ash = 90 ft^3

Bottom ash = 80 ft^3

Dry FGD sludge = 80 ft^3

Atmospheric Emissions

CO_2 = 44/12 Carbon content

SO_2 = 0.4 lb per million Btu assuming a scrubber efficiency of 90%. The emission standard is 1.2 lb per million Btu (Max)[a]

Particulates = 0.03 lb per million Btu (Max)[a]

NO_x = 0.6 lb per million Btu (Max) for bituminous coal[a]

0.5 lb per million Btu (Max) for sub-bituminous coal[a]

(a) 40 CFR 60.42a

Nuclear Fuel Cycle

The assumptions used in the nuclear scenarios are shown in Table 18.

In the United States, uranium is produced from underground and surface mines. The uranium content in the ore is low, about 0.2% for underground and about 0.1% for surface. Uranium is also produced as a by-product of other mining operations. The uranium is concentrated in mills located near the mines. Mill tailings are ponded near the mill; some are returned to the mine as backfill. Disposal practices must guard against excessive radon releases from mill tailings to nearby populations. Uranium imports are substantial in relation to domestic production. In 1984, net imports were 60% of United States production (DOE 85f, pp. 49, 77).

The mill concentrate, as ammonium diuranate, is transported by truck or train to a conversion plant where it is converted into UF_6. The UF_6 is transported by truck or train to an enrichment plant where the ^{235}U content is increased three-to-five fold. Depleted uranium tails are produced and stored at the enrichment plant.

The enriched UF_6 is transported by truck or train to a fuel fabrication plant. There it is converted to UO_2 and fabricated into fuel assemblies. The fuel assemblies are transported by truck to the reactor site.

After irradiation and cooling at the reactor site the fuel assemblies will be transported by train or truck to a national waste disposal site.

TABLE 18. Nuclear Fuel Cycle Assumptions

Ore Grade	0.14% ^{308}U
Mine Dilution	10.0%
Milling Losses	10.0%
Enrichment	3.5% ^{235}U
Tails Composition	0.25% ^{235}U
Fuel Exposure	37,500 MWd(th)/metric ton
Capacity Factor	65%

COMPARISON OF THE COAL AND URANIUM FUEL CYCLES

The coal and uranium fuel cycle requirements and waste generation for producing 1 billion kWh of electricity are summarized in Table 19. One billion kWh is roughly the electricity generation required annually by a city of 100,000. A 1000-MWe coal plant (two 500-MW units), operating at a 68% capacity factor, would consume each year six times the coal requirements shown in Table 19. The waste production correspondingly would be six times higher. Similarly, a 1000-MWe nuclear plant would consume six times the fuel and produce six times the waste shown in Table 19. One PWR fuel assembly in reaching the reference exposure generates electricity equivalent to six 100-car trains (Figure 14).

ANNUAL FUEL CYCLE REQUIREMENTS AND WASTE GENERATION FOR THE COAL AND NUCLEAR SCENARIOS

In 1984, coal generated 1317 billion kWh and nuclear generated 324 billion kWh (NERC 85, p. 37).[a] The coal consumption in 1984 was 664 million tons (DOE 85d, p. 43).[b] Nuclear fuel consumption was about 1300 metric tons (U content in fuel assemblies) (DOE 85e, p. 63). For comparison, the actual consumption and waste generation in 1984 is compared with the projected consumption and waste generation in 2035 for the all coal and all nuclear scenarios (Table 20). The fuel consumption and waste generation for intermediate years for all three scenarios are shown in Appendix G. The fuel requirements and waste generation were determined using the assumptions shown in Tables 17 and 18.

Under the all-coal scenario, coal consumption would increase about fourfold and reach 2.3 billion tons in 2035; nuclear fuel consumption would drop to

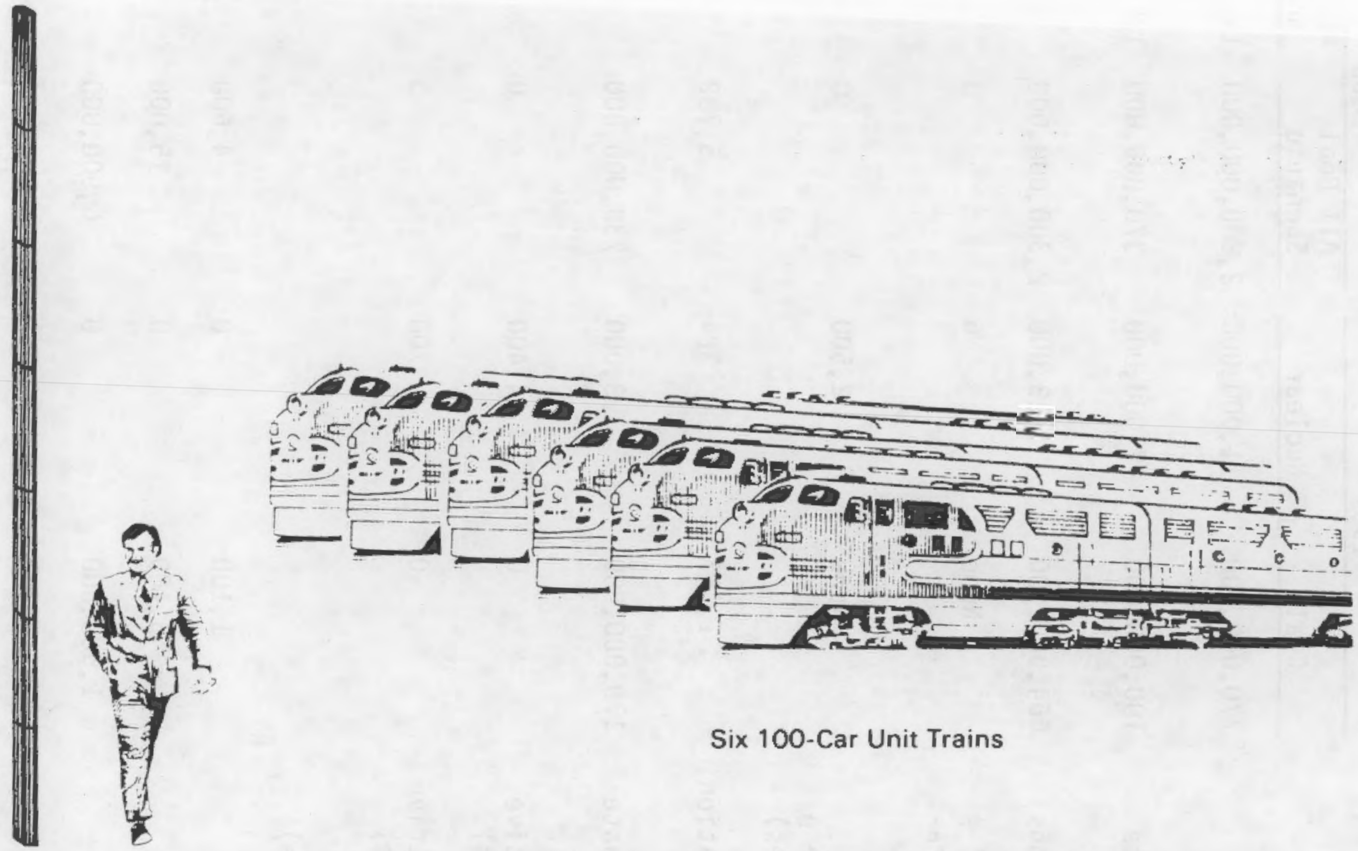
(a) Slight differences occur between NERC and EIA reported generation. EIA reports 1342 billion kWh for coal and 328 billion kWh for nuclear.

(b) The actual coal consumption in 1984 (664 million tons) was higher than would have been calculated using our long-range heat rate assumptions. We assumed 8500 Btu/kWh, which applies to state-of-the-art steam plants. The average heat rate experienced in 1984 was 10,400 Btu/kWh. Likewise, actual nuclear fuel consumption in 1984 was about 200 metric tons (U content in fuel assemblies) higher than would have been calculated since the average fuel exposure was about 20 percent less than the assumed fuel exposure.

TABLE 19. Comparison of Typical Coal and Uranium Fuel Cycle Requirements and Impacts to Produce 1 Billion kWh of Electricity

	Coal	Uranium
Mining	482,000 tons	27,800 tons
Mine and Mill Waste	77,000 tons	~27,800 tons
Transportation from Mine or Mill	405,000 tons 4500 coal cars (90-ton) 45 unit trains (100-car)	35 tons of ammonium diuranate in 56 drums (50 gal) 1 or 2 truckloads
Uranium Conversion, Enrichment, and Fabrication	Not required	13.5 yd^3 of low level waste 7.8 yd^3 non-radioactive waste 14 lb fluoride to atmosphere • 3.41 metric tons uranium fabricated and spent fuel generated • 7.6 PWR assemblies based on 450 kg/assembly • 2.25 cubic yards high-level waste (HLW) if no rod consolidation • 0.63 HLW shipments assuming rail • 3.8 HLW shipments assuming truck • 3.44 metric tons of U as 5.09 tons enriched UF_6 shipped to fabrication in 3 cylinders, 30-in. diameter by 7-feet long • 16,300 separative work units • 24 metric tons of U as 39 tons UF_6 shipped to the enrichment plant in 3 cylinders, 48-inches diameter by 13-feet long
Electricity	1,000,000,000 kWh	1,000,000,000 kWh
Solid Wastes from Power Plant	40,000 tons ash 36,000 tons dry sludge	7.6 PWR fuel assemblies (~6 tons total assembly weight)
Atmospheric Emissions from Power Plant	4,500,000 lb NO_x[a] 250,000 lb particulates[a] 10,000,000 lb SO_2[a] 1,300,000 tons CO_2	Negligible

(a) Regulatory limits, actual releases may be lower.



Six 100-Car Unit Trains

One PWR Fuel Assembly

FIGURE 14. Equivalent Electricity Generation

TABLE 20. Fuel Cycle Requirements, Electricity Generation, and Waste Generation in 1984 and 2035

	1984		2035	
	Coal	Nuclear	All Coal Scenario	All Nuclear Scenario
Mining (tons mined)	770,000,000	11,000,000	2,800,000,000	160,000,000
Mine and Mill Waste (cubic yards)	100,000,000	7,000,000	370,000,000	120,000,000
Mine Shipments (tons)	664,000,000	13,000	2,300,000,000	200,000
Uranium Enrichment (millions of separative work units)	None	6	0	94
Fuel Fabrication (Equivalent number of PWR fuel assemblies)	None	2,500	0	44,000
Electricity Generation (TWh)[a]	1,317	324	5,782	5,782
Non-Radioactive Waste (cubic yards)	170,000,000	3,000	739,000,000	45,000
Low Level Radioactive Waste (cubic yards)	0	4,400	0	78,000
High Level Radioactive Waste (cubic yards)	0	700	0	13,000
Gaseous Emissions (thousands of tons)				
SO_2	1,100	0	4,600	0
NO_x[b]	3,400	0	15,000	0
CO_2	1,600,000	0	6,900,000	0
F	0	0.002	0	0.042

(a) TWh = one billion kWh.
(b) Based on emission limits.

zero. The annual growth rate in coal consumption would increase gradually to 4% in 2015 and then decrease to 3% in 2035. At these low growth rates, no supply restrictions[(a)] should be encountered under existing regulations. However, there already is concern over the environmental impacts of existing coal plants. Increased coal combustion could exacerbate these impacts and lead to more stringent environmental control standards. More stringent standards, in turn, could result in lower fuel efficiency, which could lead to supply problems. The equivalent requirements and waste generation for other steps in both fuel cycles for the all coal scenario are summarized in Appendix G.

Under the all-nuclear scenario, coal consumption would drop to zero in 2035. Nuclear fuel requirements would increase to 20,000 metric tons uranium (as fuel elements) in 2035. The annual growth rate in nuclear fuel requirements would reach 7% per year in 2005 and drop to 3% in 2035. The equivalent requirements and waste generation for other parts of both fuel cycles are summarized in Appendix G for the all nuclear scenario.

Under the 50% coal/50% nuclear scenario, coal consumption would increase to 1.4 billion tons and nuclear fuel requirements would increase to 10,000 metric tons U in 2035. The coal consumption growth rate varies between 1 and 3% per year. The nuclear fuel requirements growth rate increases to 5% in 2005 then gradually decreases to 3% in 2035. The equivalent impacts on the other parts of both fuel cycles are summarized in Appendix G.

In order to compare the waste generation in more familiar terms, we converted the waste generation and resource requirements into per capita data (Table 21). Comparing the 1984 solid waste generation, coal plants produced about five garbage cans full of ash and sludge per person; nuclear plants produced less than one-quarter cup, most of which was radioactive. In 1984, coal produced about four times as much electricity as nuclear. The comparisons in 2035 are based on the all-coal and all-nuclear scenarios. In 2035, the

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(a) Although coal could be phased-in to replace existing nuclear capacity over a number of years, an immediate shutdown in nuclear capacity and replacement with coal could cause severe economic disruptions in at least five of the nine NERC regions (Table D.7). The reserve margins in these five regions would fall below 20%. Nuclear generated between 20 and 32% of the electricity in these regions in 1985; this was estimated to have increased to 22 to 35% in 1986.

TABLE 21. Per Capita Waste Generation and Resource Requirements

	1984		2035	
	Coal	Nuclear	All Coal Scenario	All Nuclear Scenario
Solid Waste				
Mine and Mill Waste	1 cup	4 teaspoonfuls	4 cups	1 cup
Nonradioactive Waste	5 garbage cans	2 teaspoonfuls	15 garbage cans	1/2 cup
Low-Level Waste	None	3 teaspoonfuls	None	3/4 cup
High-Level Waste	None	1/2 teaspoonful	None	6 teaspoonfuls
Gaseous Emissions				
CO_2	8 tons	None	21 tons	None
SO_2	9 lb	None	29 lb	None
No_x[a]	29 lb	None	92 lb	None
F	Negligible	0.00003 lb	Negligible	0.0004 lb
Resource Requirements				
Ore Mined	6,000 lb	67 lb	17,000 lb	1,000 lb
Electricity Generation				
Kilowatt Hours Produced	5,500	1,400	18,000	18,000

(a) Based on emission limits.

all-coal scenario would produce about 15 garbage cans full of sludge and ash and 21 tons of gaseous emissions, mostly CO_2; the all-nuclear scenario would produce about 2-1/2 cups of waste of which one-eighth cup would be HLW. The population is assumed to grow from 237 million in 1984 to 321 million in 2035 (Bureau of Census most likely projection to 2025, extrapolated to 2035).

CRITICAL RESOURCE REQUIREMENTS

Under the all-coal scenario, 61 billion tons of coal, cumulative, would be required through 2035; this is 25% of the United States recoverable coal reserves of 245 billion tons (NCA 85). Under the 50% coal scenario, 40 billion tons of coal are consumed, and under the all nuclear scenario, 19 billion tons of coal are consumed. Much of the coal reserves in the West are on federal lands. These lands would have to be opened to leasing and mine development. Mine development is the critical path step in the expansion of coal production. However, low growth rates in the all-coal scenario coupled with the lead time for power plant construction should be sufficient for adequate mine development.

Under the all-nuclear scenario, 4 million tons of U_3O_8 would be required through 2035; this is 56% of the mean estimate of total United States recoverable U_3O_8 of 7.07 million tons (Pi 81, p. ii). It is estimated that 4 million tons of U_3O_8 could be recovered at production costs under \$100 per pound U_3O_8 (Pi 81, p. 3.4). U_3O_8 at \$100 per pound would increase generation costs by less than 1-cent per kWh compared to current U_3O_8 costs of \$20 to \$30 per pound.

Under the 50% nuclear scenario, 2.3 million tons of U_3O_8 would be required through 2035--about 33% of the domestic recoverable U_3O_8. The costs for recovering 2.3 million tons of U_3O_8 were estimated to be under \$70 per pound (Pi 81, p. 3.4). Under the all coal scenario only 0.66 million tons, 9% of the recoverable U_3O_8, is consumed.

Mine development is also a critical path step in the expansion of uranium production. The current capacity of United States uranium mines is unknown. Many mines have been shut down because of the depressed state of the industry. If all of the ore requirements in the all-nuclear and half-nuclear scenarios were met by domestic mines, United States uranium production would reach new peaks about 1997 under both scenarios (uranium ore production peaked at 17 million tons in 1980) (DOE 85f, p. 48). The amount of uranium imports, which is a major factor in the domestic supply, will determine the need for domestic mine development. The long lead times for power plant construction and the availability of imports should provide sufficient time for expanding ore production to meet the growing needs.

Under the all-nuclear scenario, the United States capacity for separative work (currently 27 million separative work units) (DOE 85e, p. 40) is reached about 2005. At this time, new enrichment capacity or plutonium recycle would be required to maintain the reference fuel exposure, assuming no imports of enrichment services. Under the half-nuclear scenario, the separative work capacity would be reached about 2015.

The other parts of the nuclear and coal fuel cycles, except HLW disposal, are not as capital or energy intensive as enrichment. In addition, they require shorter lead times for capacity expansion than enrichment. These should present no supply constraints under the low growth rates resulting from the scenarios studied.

The federal government, through the nuclear waste policy act, is committed to providing nuclear waste repositories for HLW. Time tables have been established for spent fuel disposal that should not constrain nuclear power growth.

Reprocessing of spent nuclear fuels provides a potential alternative to expanding enrichment capacity and ore production. Reprocessing is capital intensive and requires a lengthy lead time. However, reprocessing is currently not included in fuel cycle planning; and, therefore, lack of capacity will not constrain nuclear power growth under current plans.

Thus, save for enrichment capacity, no critical fuel cycle constraints should be encountered for the scenarios evaluated.

DISCUSSION AND CONCLUSIONS

Growth in electricity demand has historically been closely linked to growth in GNP. For the first three-quarters of the twentieth century, a period of declining real electricity costs, the electricity demand grew faster than the growth in GNP. Since the 1973 oil embargo, real electricity costs have increased and the growth rate of electricity consumption has been approximately the same as that of the GNP.

During the next decade electricity demand is likely to increase at a slightly faster rate than real GNP growth because the real price of electricity is expected to decline over this period. There are several reasons for expected reductions in the real price of electricity:

- Energy supplies should remain abundant during most of the decade because of current over-capacity.
- Completion of new power plants will slow markedly, resulting in fewer additions to utility rate bases.
- Falling interest rates are permitting refinancing of existing utility debt, thus lowering fixed charges.
- Current surplus capacity will be eliminated through growth, thus increasing the overall system capacity factor.
- The potential exists for increased competition between electricity suppliers in the future.

Over the longer term, the potential exists for continued reductions in the real price of electricity through technology improvements, continued low interest rates, construction cost decreases resulting from the utilization of standardized plants, shorter construction periods, and increased regulatory stability. If the real price of electricity declines, electricity demand will probably increase at a rate faster than that of the real GNP.

On the other hand, several factors could result in increasing prices of electricity and slower growth rates over the long-term. Some possibilities are:

- Introduction of more stringent limits on emissions resulting from coal combustion has the potential for significantly increasing the costs of power generated by coal plants.
- Over-reliance on a single technology would decrease the competitive environment that now exists between technologies (e.g., coal and nuclear).
- Utilities could choose to use higher cost technologies for baseload capacity because of shorter lead times and reduced financial risks (e.g., gas turbines).
- Under-estimating growth in demand would cause increased utilization of higher cost, short lead time technologies.

Most forecasts of electricity demand project an average growth rate between 1.5 and 3.5% per year over the next three decades. Utility plans will result in a capacity expansion rate averaging 1.7% per year through 1994. This is based on an assumed average annual growth rate of electricity demand of 2.3%. This difference between the capacity expansion rate and the assumed growth rate in demand will be absorbed by current excess capacity, resulting in a near-optimum reserve margin in the mid-1990s.

It is believed to be more likely that current utility planning will result in shortages in generation capacity in the mid-1990s rather than in surpluses. Growth projections currently used by utilities tend to be slightly lower than many forecasts. Current excess capacity is primarily a result of forecasts that were based on historical trends prior to 1973. Those projections for unrealized high growth rates resulted in commitments for excess capacity before recognition was made of the dramatic changes that were occurring in the market. Current growth rates used for planning new capacity additions are so low that, in the absence of negative growth rates in demand, significant unplanned increases in the reserve margin are highly unlikely.

Existing surplus generation capacity is expected to be absorbed by increased demand during the next ten years. At that time new plants will be required for the following five years at a "best estimate" annual rate of about 30 GW per year. This is comparable to the 33 GW per year that was added during the 1973-1977 time period and is significantly more than the planned addition of about 7 GW per year during the 1991-1995 time frame.

It is important to recognize that, although the scenarios considered indicate a wide range in the need for new capacity in the 1996-2000 time frame (7 GW to 50 GW per year), once the current surplus capacity no longer exists, 10-25 GW per year will be required to meet growth needs alone (excluding the need for replacement of obsolete capacity).

The requirements for replacement of obsolete capacity have a significant impact on the need for building new plants. The average age of the current installed capacity in the United States is now 24 years and is projected to reach 30 years in 1995. Through 1985, the average age of plants at retirement was 36 years and plants slated for retirement though the year 2000 will have an average age of 37 years. Depending on the average age at retirement, during the 1995-2005 time frame, somewhere between 10 and 250 GW of capacity will have to be replaced for lifetimes ranging from 30 years to 50 years. Thus, the average annual requirement for replacement of obsolete capacity during that time frame will range from 1 GW to 25 GW.

The range of potential annual requirements for replacing old plants demonstrates the incentive for extending the lifetimes of these plants. This should give planners some sense of urgency of the need to pursue plant life extension efforts.

Based on current experience, only coal and nuclear technologies have the abundant indigenous resources and demonstrated capability to economically meet new growth requirements. In 1984, coal and nuclear plants generated 68% of the electricity; this is projected to increase to 76% in 1988. Planned additional new baseload capacity during the next 10 years is about equally divided between coal and nuclear plants. For a number of decades beyond that time frame, sufficient indigenous resources exist such that either coal or nuclear technologies alone could meet growth requirements. However, because of concerns over each energy source and because of benefits associated with utilizing both technologies, an over-dependence on either should continue to be avoided. Significant concerns and benefits are summarized below.

- The continuing fuel requirements and waste generation associated with coal plants are orders of magnitude greater than for nuclear plants. Nothing can change this. There are already concerns over the risks and environmental consequences of the existing level of coal usage. These concerns will probably limit future increases in coal usage. Research is needed to determine acceptable emission limits relevant to acid rain and possibly, in the future, to CO_2 emissions. Also needed will be the technologies to meet future emission limits and handle the solid waste residues.

- Many concerns over the safety and economic viability of nuclear power have increased public opposition and eroded utility support. These concerns threaten the future of nuclear energy and will probably limit its rate of growth until many of these concerns are resolved. Measures are needed to reduce financial risk to utilities, simplify licensing, reduce reactor construction times and costs, resolve nuclear waste disposal concerns, and alleviate public concerns about nuclear safety.

- Reliance on a single technology would lead to a less competitive environment, probably resulting in higher electricity prices, A measure of the economic success of a particular nuclear power plant design is its ability to compete economically with coal plants.

- Although we have large domestic coal reserves, 25% of it will be consumed in the next 50 years if we were to rely exclusively on coal for new baseload capacity. It is probably not in the long-term national interest to deplete this resource at that rate. Large scale utilization of imported coal is not a viable option. However, utilization of large amounts of imported uranium is feasible. Compared to coal, the transportation requirements are orders of magnitude lower. Additionally, nuclear power still holds the promise for extending domestic uranium reserves for several centuries through the use of breeder reactors.

All of the foregoing data point to the general conclusion that new base load plants must and will be constructed. It is in the best interest of the United States and the world to develop and apply the best technology to make maximum use of limited resources to meet future energy demands, notably electricity. Technology improvements and waste management practices obviously must be pursued and implemented to mitigate environmental impacts from electricity generation. Improvements in safety over the entire fuel cycle are always motivating factors and considerations in technology development and application. Additions in generating capacity and improvements in the quality of generating technology are not options but imperatives.

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APPENDIX A

PROJECTIONS OF ELECTRICITY DEMAND

TABLE A.1. Projections of Electricity Demand

Source	Base Year	Base Value,[a] billions kWh	Average Annual Growth Rate, %	Fore-Cast Year	Forecast Value,[a] billions kWh	Reference
DOE-EIA (High)	1985	2492	3.8	1995	3618	1
DOE-EIA (Low)	1985	2492	2.7	1995	3252	2
DOE-EIA (Base)	1985	2492	3.2	1995	3401	3
Siegel/Sillin	1983	2310	4.5	2000	4881	4
DOE-EIA	1983	2310	3.3	1995	3410	5
Data Resources, Inc.	1983	2310	3.1	2000	3881	6
DOE	1982	2241	2.8	2000	3683	7
Electrical World	1983	2310	2.8	2000	3693	8
Dept. of Commerce	1983	2310	2.5	2000	3514	9
Ntl. Coal Assoc.	1982	2241	2.3	1995	3011	10
Wharton	1983	2310	3.0	1994	3197	11
GRI	1983	2310	2.4	2000	3457	12
Conoco, Inc.	1982	2241	2.1	2000	3257	13
R.W. Sant, et al.	1981	2286	1.5	2000	3078	14
National Audubon Society	1980	2286	-0.8	2000	1946	15

(a) All values converted to net generation. Net generation is assumed to be 9% greater than end use consumption.

TABLE A.1. (contd)

Source	Base Year	Base Value,[a] billions kWh	Average Annual Growth Rate, %	Fore-Cast Year	Forecast Value,[a] billions kWh	Reference
NERC	1983	2310	2.7	1993	3015	16
Chemical Bank	1982	2241	2.9	2000	3749	17
NERC	1984	2445	2.35	1994	3080	18
Wharton	1984	2413	2.8	1994	3180	19
DRI	1985	2499 (NERC)	2.9	1995	3325	20
Koomanoff	1983	2310	0.5	1990	2392	21
DOE-CPPA Scenario B	1982	2241	4.5	1985	2600	22
			3.2	1990	2900	
			3.0	1995	3300	
			2.8	2000	3700	
			2.5	2005	4500	
Scenario A	1982	2241	4.5	1985	2600	23
			2.9	1990	2800	
			2.4	1995	3100	
			2.2	2000	3300	
			2.1	2005	3600	
			1.9	2010	3800	
Scenario C	1982	2241	4.5	1985	2600	24
			3.4	1990	2900	
			3.1	1995	3300	
			2.9	2000	3700	
			2.7	2005	4100	
			2.6	2010	4700	
Low GNP	1982	2241	2.6	1985	2400	25
			2.5	1990	2700	
			2.0	1995	2900	
			2.0	2000	3200	
			2.0	2005	3500	
			1.9	2010	3800	

(a) All values converted to net generation. Net generation is assumed to be 9% greater than end use consumption.

TABLE A.1. (contd)

Source	Base Year	Base Value,[a] billions kWh	Average Annual Growth Rate, %	Fore-Cast Year	Forecast Value,[a] billions kWh	Reference
High GNP	1982	2241	5.8	1985	2700	26
			4.5	1990	3200	
			3.7	1995	3600	
			3.4	2005	4100	
			3.2	2015	4600	
			3.0	2010	5200	
Roles Reference Cases	1980	2286	3.5	1990	3200	27
			3.0	2000	4100	
			3.1	2010	5700	
Roles (Enhanced)	1980	2286	3.4	2010	6300	28
Oil Co. A	1982	2241	3.1	2000	3800	29
Oil Co. D	1982	2224	2.4	2000	3400	30
AGA	1982	2241	1.9	2000	3100	31
GRI	1982	2241	2.7	2000	3600	32
DRI	1982	2241	2.8	2000	3600	33
AES	1982	2241	1.8	2000	3000	34
ORAU	1982	2241	2.3	2000	3300	35

(a) All values converted to net generation. Net generation is assumed to be 9% greater than end use consumption.

Reference:

1-3 DOE, Energy Information Administration. "Annual Outlook for U.S. Electric Power 1985." DOE/EIA-0474 (85).

4-17 From William W. Hogan, "Energy Demand and the Outlook for Electricity." July 1985 in hearings before the Committee on Energy and Natural Resources, United States Senate, July 23 and 25, 1985. SHRG 99-253.

15 The Audubon forecast assumed the adoption of certain energy conservation policies that did not occur.

TABLE A.1. (Reference contd)

18 North American Electric Reliability Council. "1985 Electric Power Supply and Demand." Princeton, New Jersey.

19 Mark W. French. SHRG 99-253, p. 129.

20 Stephen A. Smith. SHRG 99-253, p. 148.

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27,28 DOE, Assistant Secretary for Nuclear Energy," The Role of Nuclear Power." DOE/NE-0054. July 1984.

29-35 Derived from data in DOE/PE-0029/2, p. 7-18.

APPENDIX B

PROJECTIONS OF THE RATIO OF ELECTRICITY DEMAND GROWTH TO GNP GROWTH

TABLE B.1. Projections of the Ratio of Electricity Demand Growth to GNP Growth

Number	Source	Period	Ratio
1	Siegel	1983-2000	1.29
2	AEO	1983-1995	1.14
3	Data Resources, Inc.	1983-2000	1.07
4	DOE	1982-2000	1.00
5	Electrical World	1983-2000	0.97
6	Dept. of Commerce	1983-2000	0.93
7	National Coal Assocication	1982-1995	0.92
8	Wharton	1983-1994	0.91
9	GRI	1983-2000	0.86
10	Conoco, Inc.	1982-2000	0.75
11	R.W. Sant	1980-2000	0.58
12	National Audubon Society	1980-2000	-0.32
13	DRI	1985-1995	1.00
14	Roles-Reference	1980-2010	1.15
15	Roles-Enhanced	1980-2010	1.13
16	DOE-OPPA		
	Scenario B	1982-2010	0.96
17	Scenario A	1982-2010	0.79
18	Scenario C	1982-2010	1.04
19	Low GNP	1982-2010	0.87
20	High GNP	1982-2010	1.06
21	DOE-EIA (Middle)	1985-1990	1.10
22	DOE-EIA (Middle)	1991-1995	1.35
23	DOE-EIA (Middle)	1985-1995	1.19
24	DOE-EIA (Low)	1985-1995	1.35
25	DOE-EIA (High)	1985-1995	1.12
26	Oil Co. A	1982-2000	1.11
27	Oil Co. B	1982-2000	1.00
28	AGA	1982-2000	0.66
29	GRI	1982-2000	1.04
30	DRI	1982-2000	1.00
31	AES	1982-2000	0.69
32	ORAU	1982-2000	0.79
		Mean	1.03*
		Median	1.00
		Median w/o DOE	0.93†

TABLE B.1. (contd)

Notes:

1-12	Hogan op. cit., p. 96
13	Smith op. cit., p. 149
14-15	DOE, Assistant Secretary of Nuclear Energy, op. cit.
16-20	DOE, Office of Policy, Planning and Analysis, op. cit.
21-25	DOE, EIA - 0474 (85) op. cit.
26-32	Derived from DOE (PE-0029/2, pp. 7-13 and 7-18)

* excluding Audubon projection

† excluding all DOE projections

APPENDIX C

COMPARISON OF EIA AND NERC CAPACITY AND ELECTRICITY GENERATION INFORMATION

TABLE C.1. Comparison of EIA and NERC Reported Capacity and Generation

	1984
NERC - Summer Capability	604 GW
EIA - Nameplate Capacity	672 GW (Dec. 31)
NERC - Net Generation - U.S.	2,379 Billion kWh
Net Imports	66 Billion kWh
Net requirements for Load	2,446 Billion kWh
EIA - Net Generation	2,413 Billion kWh

All figures are for contiguous states.
Sources: NERC 85 and DOE 85a.

APPENDIX D

SUMMARY OF EXISTING U.S. POWER PLANTS

TABLE D.1. Existing U.S. Power Plants, 1985

Type	Units Number	Size Range, MW	Total Capacity, GW	Average Capacity, MW
Steam	2,660	0.5 to 1300	467.3	176
Hydro	3,504	0.03 to 700	84.8	24
Nuclear	91	50 to 1372	81.4	894
Gas Turbine	1,378	0.8 to 206	47.7	35
Combined Cycle	132	1 to 340	8.5	65
Internal Combustion	3,093	0.02 to 42	5.2	2
Geothermal	23	3 to 140	1.7	72
Wind, solar	23	0.01 to 12	<0.1	1
TOTAL[a]	10,904	0.01 to 1372	695.5	64

(a) Does not include 16 units with a total capacity of 5.7 GW that are completed but not yet in commercial operation.
Source: EIA data tape, February 1986.

TABLE D.2. Inventory of Steam Power Units

Service Date	Number	Size Range, MW	Total Capacity, GW	Average Capacity, MW
-1920	20	1 to 35	0.2	12
1921-1940	176	1 to 160	3.5	20
1941-1950	403	0.75 to 153	15.4	38
1951-1960	930	0.5 to 496	90.0	97
1961-1970	564	2.5 to 1150	126.5	224
1971-1980	403	1 to 1300	183.6	456
1981-1985	102	0.8 to 1300	46.3	454
Unknown	62	2 to 90	1.7	27
TOTAL	2660[a]	0.5 to 1300	467.3[a]	176

(a) Does not include 2 units (0.9 GW) which are completed but not in commercial operation.
Source: EIA data tape, February 1986.

TABLE D.3. Inventory of Nuclear Power Units

Service Date	Number	Size Range, MW	Total Capacity, GW	Average Capacity, MW
-1970	11	75 to 860	5.9	536
1971-1980	58	50 to 1216	50.0	862
1981-1985	22	850 to 1372	25.4	1157
TOTAL	91	50 to 1372	81.4	894

Source: EIA data tape, February 1986.

TABLE D.4. Inventory of Hydro Power Units

Service Date	Number	Size Range, MW	Total Capacity, GW	Average Capacity, MW
-1920	892	0.04 to 24	2.6	3
1921-1940	994	0.05 to 83	7.5	8
1941-1950	286	0.06 to 129	5.3	18
1951-1960	455	0.1 to 90	14.7	32
1961-1970	450	0.1 to 204	24.5	54
1971-1980	219	0.2 to 700	23.6	108
1981-1985	208	0.03 to 351	6.8	33
TOTAL	3504	0.03 to 700	84.9	24

Source: EIA data tape, February 1986.

TABLE D.5. Inventory of Gas Turbine Power Units

Service Date	Number	Size Range, MW	Total Capacity, GW	Average Capacity, MW
-1960	11	1 to 12	0.1	6
1961-1970	602	0.8 to 146	14.1	23
1971-1980	739	0.8 to 206	32.0	43
1981-1985	25	1.5 to 170	1.6	65
Unknown	1	20	30.0	0
TOTAL	1378	0.8 to 206	47.7	35

Source: EIA data tape, February 1986.

TABLE D.6. Age of Existing Capacity

Years of Startup	Number of Units	Capacity, GW Total	Capacity, GW Cumulative
-1900	33	0.03	0
1901-1910	310	0.6	1
1911-1920	574	2.2	3
1921-1925	462	2.4	5
1926-1930	414	3.7	9
1931-1935	195	1.7	11
1936-1940	441	3.5	14
1941-1945	353	6.7	21
1946-1950	933	14.6	35
1951-1955	1128	48.7	84
1956-1960	921	57.0	141
1961-1965	989	64.2	205
1966-1970	1525	109.2	315
1971-1975	1402	183.1	498
1976-1980	602	115.6	613
1981-1985	557	81.7	695
Unknown	65	1.7	697
Testing	18	6.9	703

Average Age of Units: 31 years

Average Age of Capacity: 24 years

Source: EIA data tape, February 1986.

TABLE D.7. Regional Nuclear Capacity and Generation (NERC 86, pp 26, A-2)

Region	1985 Nuclear Capacity,[a] GW	Total Capacity, %	Total Capacity, GW	1985 % Electricity Generation by Nuclear
ECAR	4.4	4.7	93.0	5.5
ERCOT	0	0	43.8	0
MAAC	9.4	19.9	47.2	25.6
MAIN	9.9	22.2	44.6	31.7
MAPP	3.7	12.9	28.7	19.5
NPCC	7.9	15.4	51.3	23.2
SERC	25.1	19.1	131.4	24.2
SPP	3.8	6.1	62.2	8.4
WSCC	6.9	5.8	119.4	7.2
U.S. Total	71.3[b]	11.5	621.6[b]	15.1

(a) Summer.
(b) Totals may not add due to rounding.

APPENDIX E

SUMMARY OF RETIRED POWER PLANTS

TABLE E.1. Retired Capacity by Type through 1985

Type	Number	Total Capacity, GW	Average Capacity, MW	Average Life, yrs
Steam	759	19.2	25	38
Gas Turbine	51	1.1	21	14
Nuclear	6	1.0	161	21
Internal Combustion	835	0.9	1	27
Combined Cycle	11	0.3	31	46
Hydro	112	0.2	2	54
Wind Turbine	2	0.0	2	4
TOTAL[a]	1776	22.7	12.8	36

(a) Excludes 414 units (5.3 GW) with unknown startup or retirement dates.

Note: Tables E.1 through E.4 were generated by the authors using an EIA data tape, dated February, 1986.

TABLE E.2. Retired Steam Capacity through 1985

Type	Number	Total Capacity, GW	Average Capacity, MW	Average Life, yrs
Coal	242	5.9	24	37
Oil	235	8.0	34	39
Gas	258	5.1	20	38
Other	24	0.2	7	42

TABLE E.3. Retirement by Year of Startup

Startup Period	Number Retired	Capacity Retired, GW	Average Capacity, MW	Cumulative Retirement	Cumulative Capacity
1900-1910	21	0.05	2	21	0.05
1911-1920	83	0.07	8	104	0.07
1921-1930	358	5.4	15	462	6.2
1931-1940	331	3.1	9	793	9.3
1941-1950	626	7.4	12	1419	16.7
1951-1960	328	4.8	15	1747	21.4
1961-1970	200	2.1	11	1947	23.6
1971-1980	70	0.7	10	2017	24.3
1981-1985	10	0.1	9	2027	24.3
Unknown	163	3.7	23	2190[a]	28.0

(a) Includes 27 units (0.13 GW) sold to non-utilities, and not currently operating.

TABLE E.4. Retirement of Capacity by Time of Retirement

Retirement Period	Number Retired	Capacity Retired, GW	Average Capacity, MW	Cumulative Retirement	Cumulative Capacity	Average Life, yr
-1940	3	0.0	1	3	0.0	15
1941-1960	18	0.0	2	21	0.0	23
1961-1970	19	0.0	1	40	0.0	27
1971-1975	204	3.0	14	244	3.0	38
1976-1980	501	6.3	12	745	9.3	38
1981-1985	1031	13.5	13	1776	22.7	35
1986-1990[a]	245	5.9	24	2021	28.6	36
1991-1995[a]	154	8.3	54	2175	36.9	36
1996-2000[a]	41	3.2	78	2216	40.1	39
2001-2010[a]	66	8.9	135	2282	48.9	38

(a) Based on projections.

APPENDIX F

SUMMARY OF PLANNED ADDITIONS

TABLE F.1. Planned Increases in Installed Capability to 1994

	Net Increase in Summer Capability Over 1984 (GW)	Percent
Coal	50	47
Nuclear	50	47
Hydro	4	4
Geothermal	2	2
Oil	(2)	(2)
Gas	(2)	(2)
Dual Fuel	(2)	(2)
Other	9	8
TOTAL[a]	107	100

(a) May not add due to rounding.
Source: NERC 85, p. 17.

APPENDIX G

ANNUAL WASTE GENERATION AND FUEL CYCLE REQUIREMENTS IN SELECTED YEARS FOR THE THREE SCENARIOS

TABLE G.1. Resource Requirements for Electricity Generation and Waste Products for the Three Scenarios

Electricity Generation (Billions of kWh)

	All Coal Case		50/50 Case		All Nuclear Case	
Year	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
1984	1317	324	1317	324	1317	324
1995	1568	586	1568	586	1568	586
2005	2159	597	1725	1032	1290	1467
2015	3135	393	1902	1627	668	2860
2025	4335	182	2299	2218	262	4254
2035	5782	0	2891	2891	0	5782

Annual Rate of Change in Generation for Selected Years (% Change from Previous Year)

	All Coal Case	50/50 Case		All Nuclear Case
Year	Coal	Coal	Nuclear	Nuclear
1995	3	3	1	1
2005	3	1	5	7
2015	4	2	4	6
2025	4	3	2	3
2035	3	2	3	3

Millions of Tons of Coal or Ore Mined

	All Coal Case		50/50 Case		All Nuclear Case	
Year	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
1984	635	9	635	9	635	9
1995	756	16	756	16	756	16
2005	1040	17	831	29	622	41
2015	1511	11	916	45	322	80
2025	2089	5	1108	62	126	118
2035	2786	0	1393	80	0	161

Thousands of Cubic Yards of Nonradioactive Solids

	All Coal Case		50/50 Case		All Nuclear Case	
Year	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
1984	168356	3	168356	3	168356	3
1995	200442	5	200442	5	200442	5
2005	275991	5	220512	8	164905	11
2015	400756	3	243138	13	85392	22
2025	554156	1	293888	17	33492	33
2035	739130	0	369565	23	0	45

Thousands of Tons of Coal or Uranium Shipped

	All Coal Case		50/50 Case		All Nuclear Case	
Year	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
1984	533072	11	533072	11	533072	11
1995	634667	21	634667	21	634667	21
2005	873881	21	698214	36	522143	51
2015	1268929	14	769857	57	270381	100
2025	1754643	6	930548	78	106048	149
2035	2340334	0	1170167	101	0	202

Cubic Yards of Low Level Radioactive Waste

	All Coal Case		50/50 Case		All Nuclear Case	
Year	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
1984	0	4374	0	4374	0	4374
1995	0	7911	0	7911	0	7911
2005	0	8060	0	13932	0	19805
2015	0	5306	0	21965	0	38610
2025	0	2457	0	29943	0	57429
2035	0	0	0	39029	0	78057

TABLE G.1. (contd)

Millions of Cubic Yards of Mine and Mill Waste

Year	All Coal Case		50/50 Case		All Nuclear Case	
	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
1984	84	6	84	6	84	6
1995	99	12	99	12	99	12
2005	137	12	109	21	82	29
2015	199	8	121	33	42	57
2025	275	4	146	44	17	85
2035	367	0	183	58	0	116

Cubic Yards of High Level Radioactive Waste

Year	All Coal Case		50/50 Case		All Nuclear Case	
	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
1984	0	729	0	729	0	729
1995	0	1319	0	1319	0	1319
2005	0	1343	0	2322	0	3301
2015	0	884	0	3661	0	6435
2025	0	410	0	4991	0	9572
2035	0	0	0	6505	0	13010

Number of 100 Car Coal Trains

Year	All Coal Case		50/50 Case		All Nuclear Case	
	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
1984	30001	0	30001	0	30001	0
1995	35719	0	35719	0	35719	0
2005	49182	0	39296	0	29386	0
2015	71415	0	43328	0	15217	0
2025	98751	0	52371	0	5968	0
2035	131714	0	65857	0	0	0

Millions of Separative Work Units for Uranium Enrichment

Year	All Coal Case		50/50 Case		All Nuclear Case	
	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
1984	0	5	0	5	0	5
1995	0	10	0	10	0	10
2005	0	10	0	17	0	24
2015	0	6	0	27	0	47
2025	0	3	0	36	0	69
2035	0	0	0	47	0	94

Millions of Tons of Carbon Dioxide Released

Year	All Coal Case		50/50 Case		All Nuclear Case	
	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
1984	1564	0	1564	0	1564	0
1995	1862	0	1862	0	1862	0
2005	2563	0	2048	0	1532	0
2015	3722	0	2258	0	793	0
2025	5147	0	2730	0	311	0
2035	6865	0	3432	0	0	0

Requirements* for Spent Fuel Shipments Assuming Rail (Multiply by Six for Truck)

Year	All Coal Case		50/50 Case		All Nuclear Case	
	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
1984	0	205	0	205	0	205
1995	0	370	0	370	0	370
2005	0	377	0	652	0	926
2015	0	248	0	1027	0	1806
2025	0	115	0	1401	0	2686
2035	0	0	0	1826	0	3651

*Active shipments of spent fuel will not begin until a licensed facility becomes available.

TABLE G.1. (contd)

Thousands of Tons of Sulfur Oxides Released (Assuming 90% Recovery in Scrubbers)

	All Coal Case		50/50 Case		All Nuclear Case	
Year	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
1984	1054	0	1054	0	1054	0
1995	1254	0	1254	0	1254	0
2005	1727	0	1380	0	1032	0
2015	2508	0	1522	0	534	0
2025	3468	0	1839	0	210	0
2035	4626	0	2313	0	0	0

Tons of Flouride Released To Air

	All Coal Case		50/50 Case		All Nuclear Case	
Year	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
1984	0	2	0	2	0	2
1995	0	4	0	4	0	4
2005	0	4	0	7	0	11
2015	0	3	0	12	0	21
2025	0	1	0	16	0	31
2035	0	0	0	21	0	42

Cumulative Generation (billions of kWh) from Coal Plus Nuclear Plants

	All Coal Case		50/50 Case		All Nuclear Case	
Year	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
1995	15239	5760	15239	5760	15239	5760
2005	21003	6550	18271	9282	15539	12014
2015	26330	5323	18132	13521	9934	21719
2025	37597	2921	20883	19635	4169	36349
2035	51500	367	26231	25636	962	50905

Thousands of Tons of Oxides of Nitrogen Released (Assuming Maximum Allowable Release)

	All Coal Case		50/50 Case		All Nuclear Case	
Year	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
1984	3358	0	3358	0	3358	0
1995	3998	0	3998	0	3998	0
2005	5505	0	4399	0	3290	0
2015	7994	0	4850	0	1703	0
2025	11054	0	5862	0	668	0
2035	14744	0	7372	0	0	0

Cumulative Consumption of Coal and U308 in Millions of Tons

	All Coal Case		50/50 Case		All Nuclear Case	
Year	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
1995	6168	0.18	6168	0.18	6168	0.18
2005	14669	0.39	13564	0.47	12458	0.56
2015	25327	0.55	20903	0.90	16479	1.24
2025	40545	0.65	29355	1.51	18166	2.38
2035	61390	0.66	39973	2.32	18556	3.98

APPENDIX H

NERC REGIONS

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interconnected Network

MAPP
Mid-continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Sytems Coordinating Council

APPENDIX I

HISTORICAL DATA: INSTALLED CAPACITY AND NET CAPACITY ADDITIONS

TABLE I.1. Historical Data: Installed Capacity and Net Capacity Additions

	Installed Nameplate Capacity, GW	Net Capacity Addition, GW		Installed Nameplate Capacity, GW	Net Capacity Addition, GW
1926	23	-	1956	121	6
1927	25	2	1957	129	8
1928	28	3	1958	143	14
1929	30	2	1959	157	14
1930	32	2	1960	168	11
1931	34	2	1961	181	13
1932	34	0	1962	191	10
1933	35	1	1963	211	20
1934	34	(1)	1964	222	11
1935	34	0	1965	236	14
1936	35	1	1966	248	12
1937	36	1	1967	269	21
1938	38	2	1968	291	22
1939	39	1	1969	313	22
1940	40	1	1970	342	29
1941	42	2	1971	369	27
1942	45	3	1972	399	30
1943	48	3	1973	442	43
1944	49	1	1974	478	36
1945	50	1	1975	508	30
1946	50	0	1976	531	23
1947	52	2	1977	560	29
1948	57	5	1978	579	19
1949	63	6	1979	598	19
1950	69	6	1980	614	16
1951	76	7	1981	635	21
1952	82	6	1982	650	15
1953	92	10	1983	658	8
1954	103	11	1984	672	14
1955	115	12			

Source: DOE 85a, pp. 60-61.

APPENDIX J

PROJECTIONS OF PEAK DEMANDS, CAPACITY, AND ANNUAL ADDITIONS FOR THE THREE SCENARIOS

TABLE J.1. Projections (GW) for the High, Middle, and Low Demand Scenarios

	Projected Peak Demand			Projected Capacity			Annual Additions[a]		
	Growth Rate			Reserve Margins			Average Service Life, Years		
YEAR	1.50%	2.50%	3.50%	15.00%	20.00%	25.00%	50	40	30
1984	451	451	451	604	604	604			
1985	458	462	467	611	617	617	7	13	23
1986	465	474	483	617	639	639	7	22	28
1987	472	486	500	628	655	655	11	18	24
1988	479	498	518	639	664	664	13	13	22
1989	486	510	536	647	672	672	9	14	21
1990	493	523	555	655	676	693	9	9	31
1991	501	536	574	659	687	717	7	17	36
1992	508	550	594	664	694	743	7	13	34
1993	516	563	615	668	704	769	7	19	43
1994	524	578	636	672	712	795	5	17	38
1995	531	592	659	674	720	823	3	19	40
1996	539	607	682	676	728	852	2	14	39
1997	547	622	706	681	746	882	7	26	49
1998	556	637	730	687	765	913	9	31	50
1999	564	653	756	690	784	945	9	32	52
2000	573	670	782	694	804	978	9	30	59
2001	581	686	810	699	824	1012	11	32	59
2002	590	704	838	704	844	1048	11	30	62
2003	599	721	867	708	865	1084	12	39	76
2004	608	739	898	712	887	1122	14	32	70
2005	617	758	929	716	909	1161	15	35	67
2006	626	777	962	720	932	1202	10	33	61
2007	635	796	995	731	955	1244	18	43	68
2008	645	816	1030	742	979	1288	23	43	61
2009	655	836	1066	753	1004	1333	24	44	62
2010	664	857	1103	764	1029	1379	21	51	60
2011	674	879	1142	776	1054	1428	23	50	67

(a) Includes replacement of obsolete capacity based on service life assumptions.

TABLE J.1. (contd)

	Projected Peak Demand			Projected Capacity			Annual Additions[a]		
	Growth Rate			Reserve Margins			Average Service Life, Years		
YEAR	1.50%	2.50%	3.50%	15.00%	20.00%	25.00%	50	40	30
2012	684	901	1182	787	1081	1478	21	53	64
2013	695	923	1223	799	1108	1529	29	66	59
2014	705	946	1266	811	1136	1583	23	59	66
2015	716	970	1311	823	1164	1638	25	56	68
2016	726	994	1356	835	1193	1696	23	50	79
2017	737	1019	1404	848	1223	1755	32	56	75
2018	748	1045	1453	861	1253	1816	32	48	71
2019	760	1071	1504	874	1285	1880	33	49	72
2020	771	1097	1557	887	1317	1946	39	46	87
2021	783	1125	1611	900	1350	2014	38	52	92
2022	794	1153	1667	914	1384	2084	40	48	96
2023	806	1182	1726	927	1418	2157	53	42	99
2024	818	1211	1786	941	1454	2233	46	48	102
2025	831	1242	1849	955	1490	2311	42	49	106
2026	843	1273	1913	970	1527	2392	35	59	110
2027	856	1305	1980	984	1565	2476	41	54	114
2028	869	1337	2050	999	1605	2562	32	49	118
2029	882	1371	2121	1014	1645	2652	32	48	122
2030	895	1405	2196	1029	1686	2745	29	45	126
2031	908	1440	2273	1045	1728	2841	35	53	130
2032	922	1476	2352	1060	1771	2940	29	50	135
2033	936	1513	2434	1076	1815	3043	23	55	140
2034	950	1551	2520	1092	1861	3150	29	53	144
2035	964	1589	2608	1109	1907	3260	23	55	150

(a) Includes replacement of obsolete capacity based on service life assumptions.

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