Chapter 3

Electric Utilities in the 1990s: Planning for an Uncertain Future

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Electric Utilities in the 1990s: Planning for an Uncertain Future

INTRODUCTION

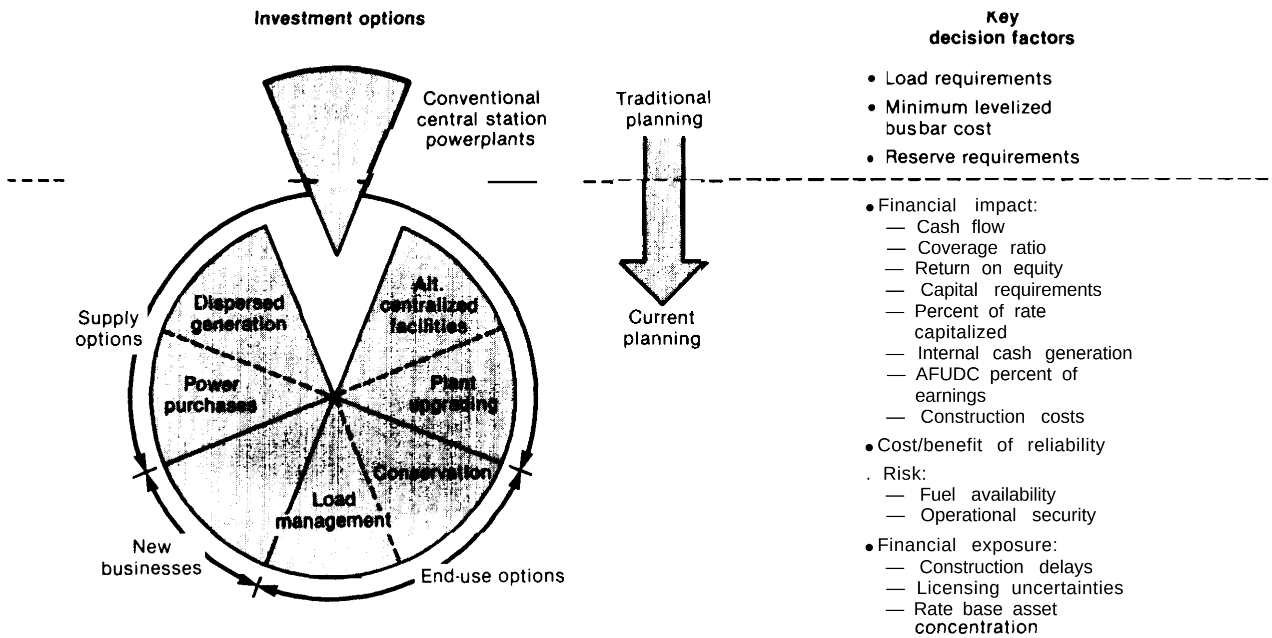
Overview

In the early 1970s, the U.S. electric power industry entered a new era. Long a stable force in the U.S. economy, the industry as a whole emerged in the 1980s under considerable financial stress and uncertainty, precipitated by skyrocketing fuel prices, escalating capital and construction costs, and a declining and erratic demand growth.

Even as utilities recovered from the shocks of the 1970s, it was clear that they would not return to business as usual, circa 1960s. The highly uncertain decision environment has forced utilities to reexamine their traditional business strategies as they look to the 1990s and beyond. indeed, the basic procedures traditionally used by utilities in making future investment decisions have, in many cases, been drastically changed by the utilities themselves as well as by security analysts, investors, regulators, and ratepayers.

In this chapter we examine the strategic options being considered by utilities over the next two decades and, in particular, focus on the circumstances under which investment in new generating technologies might play a significant role for electric utilities through this period, compared with other strategic options. These other cptions include continued reliance on conventional supply sources, life extension and repowering of existing plants, increased purchases of power from neighboring utilities, or diversification to other nonutility lines of business (see figure 3-1). In addition, we review the arguments for and against the use of alternative technologies under different planning scenarios.

Figure 3-1.—Utility Investment Alternatives



SOURCE: Adapted from D. Geraghty, "Coping With Changing Risks in Utility Capital Investments," unpublished paper, Electric Power Research Institute, February 1984.

The extent to which new generating technologies might play a role in electric utilities in the 1990s depends on how favorably such technologies compare with capital investments in conventional generation alternatives. It also depends on the managerial skills and financial resources of individual utilities. The role of nonutility producers of electricity is discussed later.

A number of 1982 surveys[1] suggested that utilities are not very interested in investing in new generating technologies. A variety of contingencies—such as persistent cost-control problems with large, central-station coal or nuclear plants now under construction or increased environmental control requirements, e.g., to reduce acid rain—however, are beginning to make such investments look much more appealing to utilities in the 1990s.

Currently, much of the investment in new electric generating technologies in the United States is not being undertaken by utilities at all, but by nonutility owners generating power under the provisions of the Public Utility Regulatory Policies Act of 1978 (PURPA) (see box 3A). To date, much of this investment has gone into cogeneration. in some utility service areas, e.g., in California, the rate of growth of new generating technologies is steadily increasing (see figure 3-2).[2] Hence, the degree to which nonutility investment in new generating technologies (and load management) affects the total generation mix is also an important ingredient in the future of the U.S. electric power system.

The ultimate penetration of new technologies over the next two decades in many regions may well hinge on the relationship which evolves between utilities and nonutility owners. It will depend on the stringency of the utilities' interconnection requirements and on the rates the nonutility electricity producers receive for their electricity from the utilities. At present, these requirements and rates vary greatly across the United States (see chapter 7).

Box 3A.—The Public Utility Regulatory Policies Act of 1978

The Public Utility Regulatory Policies Act (PURPA), enacted in 1978, required the Federal Energy Regulatory Commission (FERC) to promulgate rules (under Section 210 of the Act) mandating purchase of electricity from qualifying small power producers (qualifying facilities—QFs) at rates "just and reasonable" to consumers, nondiscriminatory against producers, and not in excess of the incremental cost to the electric utility of electricity from other sources, i.e., if the purchasing utility generated the power itself. In its final rules implementing Section 210, FERC left the establishment of "avoided cost" rates up to the States to determine but also permitted States to set such rates higher than full avoided costs should it be found in the public interest to encourage cogeneration and small power production. Most States have issued implementing orders or at least interim rules for this PURPA requirement but the methods used have been quite varied (see chapter 7).

In establishing avoided cost rates, a principal area of variation among the States has been in evaluating QFs to receive *capacity payments*, granted as part of a QF's negotiated avoided cost rate when firm peak capacity is provided to the utility, allowing the purchasing utility to cancel or defer construction of new generating facilities. Less of an issue, although still varying widely among the States, is the establishment of *energy credits*, i.e., the value of the fuel or purchased power displaced by the QF.

Even though PURPA has been in effect for over 5 years, its implications are only beginning to be realized in many areas of the country. In some areas, such as California and the Southwest where avoided cost rates are high due to high fuel costs of existing generation, the contribution to total installed capacity by QFs is likely to be quite significant over the next two decades. This likelihood adds yet another dimension to the complicated investment planning problems facing utilities; these complications are discussed later in this chapter and in chapter 6.

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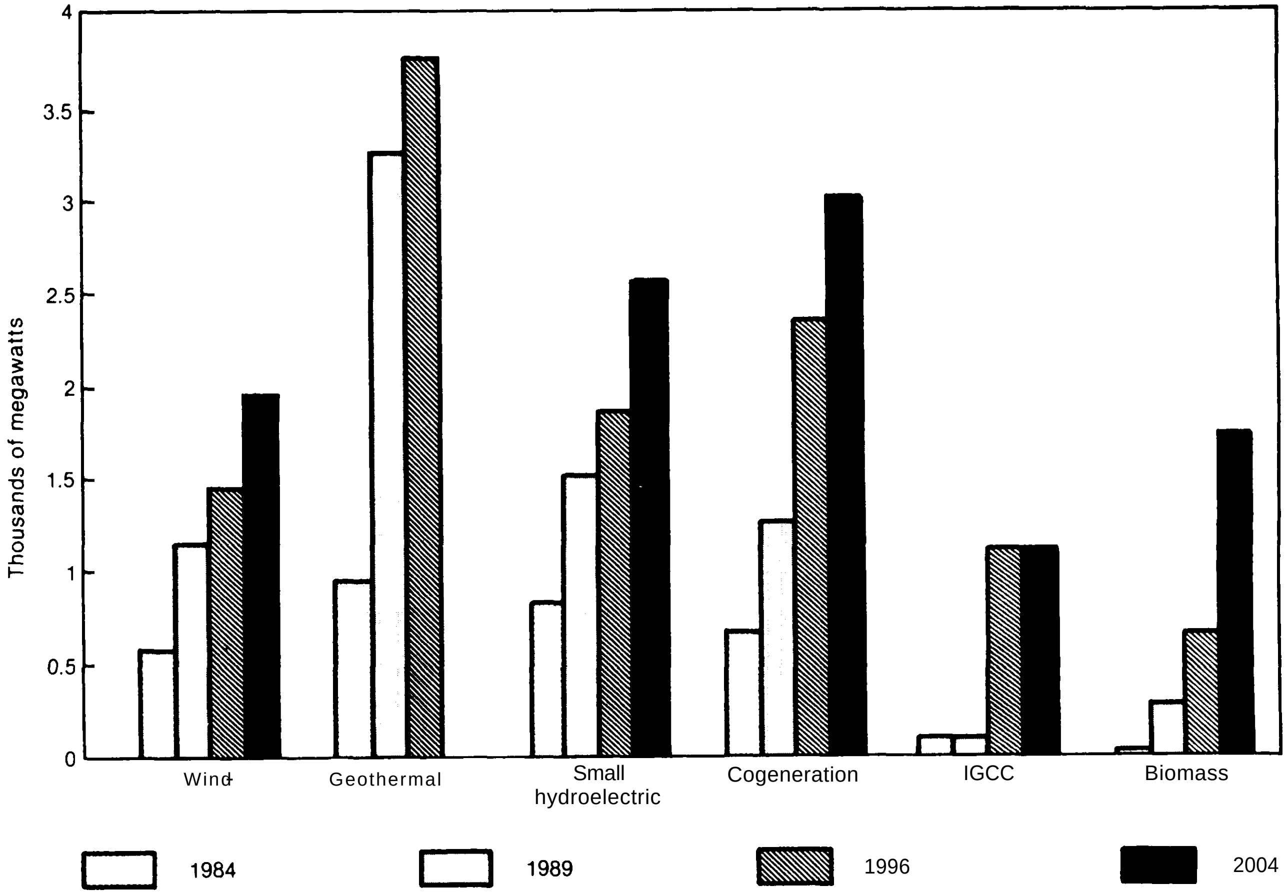
[1] "Plans and Perspectives: The Industry's View," *EPRI journal*, October 1983; Douglas Cogan and Susan Williams, *Generating Energy Alternatives: Conservation, Load Management, and Renewable Energy at America's Electric Utilities* (Washington, DC: Investor Responsibility Research Center, Inc., 1983); *A Review of Energy Supply Decision Issues in the U.S. Electric Utility Industry* (Washington, DC: Theodore Barry & Associates, September 1982).

[2] Th is rate of growth has been so fast in California that the State declared a temporary moratorium on cogeneration projects in late 1984; the figure shows both utility and nonutility involvement in alternative technology projects.

Figure 3-2.—Alternative Power Generation in California (utility and nonutility owned capacity)



Projections were also made for photovoltaics—11 MW by 2004. All projections were made based on currently offered standard offers from California utilities; the total 1989 projected levels of penetration of cogeneration wind, small hydroelectric, photovoltaics, and energy from biomass total 6,290 MW.

SOURCE: Californnia Energy Commission, "Resource Estimates of Small Power Technologies in California," unpublished, 1984.

Historical Context

Overview

The basic framework for planning, forecasting, and analysis used today by the electric power industry in the United States is primarily the result of an industry-government relationship that has evolved since the earliest days of the industry.[3] The Federal Power Act of 1935 standardized the operating characteristics in the industry. Perhaps the most important feature of this legislation was not so much its guidelines for standardization, but more its general mandate for the industry:

> Provide an abundant supply of electric power with the greatest possible economy and with regard to proper utilization and conservation of natu rat resources.

In practice, this mandate was interpreted as requiring the provision of power at any time of day and in any quantity demanded.[4] As a result, the

[3] In these early days power systems of two basic designs were evolving simultaneously, namely the DC power system advocated initially by Thomas Edison and the AC network initiated by George Westinghouse. Indeed, in these early days some major cities maintained two independent parallel distribution systems, sometimes even strung on the same utility poles. The AC system eventually prevailed, of course, largely due to the use of transformers which permitted stepping up transmission voltages for higher efficiency and stepping down distribution voltages for safer and easier use; see P. Sporn, *Vistas in Electric Power* (New York: McGraw Hill, 1968).

[4] This mandate is not the rule in many foreign countries which has led to quite a different history of electric power production in these countries.

primary objective of electric utility operations in the United States is to meet the collective demand presented by all of its customers. The Federal Power Act required that this demand be met in an economically efficient manner both in dispatching generators to meet the daily load as well as in developing plans for new construction.

Until the late 1960s, electric utilities had been able to reliably and economically plan additions to their installed generating capacity to meet future demand while retiring aging plants. Until that time, demand growth forecasts had been reasonably accurate, powerplant construction lead times had been reasonably predictable, and construction as well as fuel cost changes had been small. Construction costs (per kilowatt installed) in fact decline as power-plants are scaled up in size. Electric utilities were viewed as sound investment opportunities by the capital markets. Thus, capital was available at relatively low cost.

Since the late 1960s, however, several factors have combined to create problems for the electric utilities. Both their financial performance and ability to make system planning decisions using the planning tools of the past have deteriorated as a result. Among these factors (discussed in more detail in the next section) are: 1) the growing difficulty of making demand forecasts—the industry as well as nearly all interested parties consistently underestimated the potential for conservation, i.e., the price elasticity of demand; 2) the dramatic increase in environmental protection costs resulting from the public's growing concern over the environmental effects of electric power production, especially air pollution from coal; 3) the unprecedented and escalating cost of new powerplants, especially nuclear powerplant construction due to unexpected delays, inflated capital costs, stricter safety standards (especially after Three Mile island), unpredictable regulation, and uneven project management; and 4) high as well as uncertain fuel prices and supplies. The legacy of this traumatic period has been an industry in which both investors and utility managers are acutely aware of the industry's financial fragility and uncertain demand outlook and are therefore more cautious about committing their capital to large new coal and nuclear plants.

The prognosis for the power industry is uncertain. While it is possible that demand growth rates may increase once again over the next decade, it is also possible that changing industry fuel choices, saturation of electricity use in buildings, and improved efficiency of electricity use in all sectors of the economy as well as other conservation measures may moderate demand growth to less than 2 percent per year. Most current estimates range from 1.5 to 5 percent per year (see figure 3-3). The issue of uncertainty in demand growth is discussed in more detail in a previous OTA assessments

In the following, the impact these interrelated financial, regulatory (including environmental), and cost escalation stresses have had on the decisionmaking environment in the electricity industry are sketched in more detail.

Increasing Fuel Prices and Supply Uncertainty

Figure 3-4 shows the national average fossil fuel prices paid by electric utilities in the United States over the last decade; weighted average fossil fuel prices more than tripled between 1970 and 1980. Those utilities relying on significant levels of oil and natural gas (principally the East and Southwest—see figures 3-5 and 3-6) are shifting their generation mix to more capital-intensive nuclear and coal generation due to the uncertain future costs and supply of oil and natural gas. The recent stabilizing of oil and natural gas prices and excess supply of natural gas has only added to the uncertainty about future supply and prices.b (The regional variations in generation mix, fuels and other factors are discussed in chapter 7.)

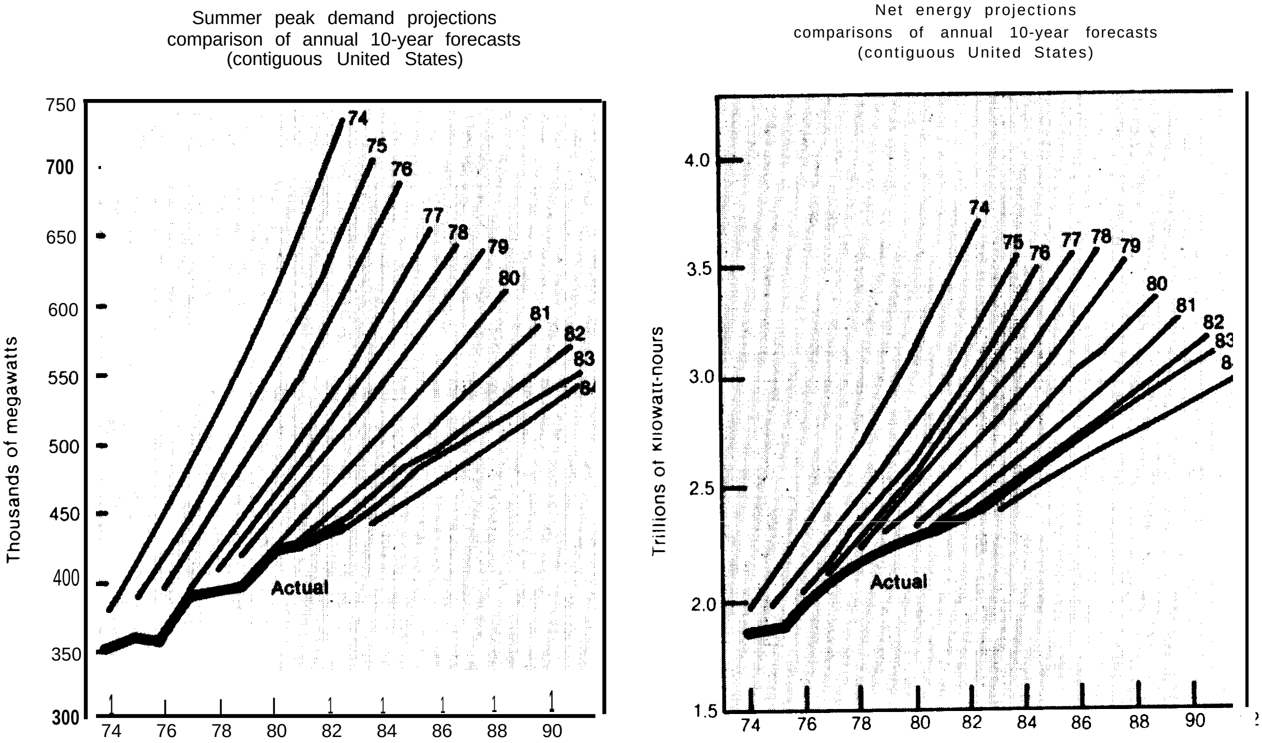
Increasing Powerplant Construction Costs

Increased attention to environment and safety issues over the last decade has contributed to both extended lead times in the siting, permit-

[5]U.S. congress, Office of Technology Assessment, *Nuclear Power in an Age of Uncertainty* (Washington, DC: U.S. Government Printing Office, February 1984), OTA-E-216, ch. 3.

[6]See U.S. Congress, Office of Technology Assessment, *U.S. Natural Gas Availability: Gas Supply Through the Year 2000* (Washington, DC: U.S. Government Printing Office, February 1985), OTA-E-245.

Figure 3.3.—Projections of U.S. Electric Load Growth

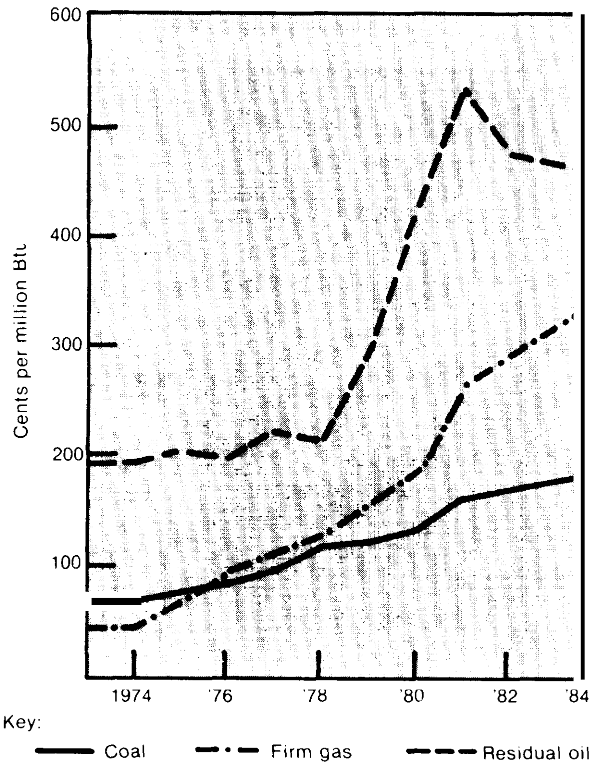


Average annual growth rate (o/o) projecting 10-years	Average annual growth rate (o/o) projecting 10-years
1974 -7.6	1974 -7.5
1975 -6.9	1975 -6.7
1976 -6.4	1976 -6.3
1977 -5.7	1977 -5.8
1978 -5.2	1978 -5.3
1979 -4.7	1979 -4.8
1980 -4.0	1980 -4.1
1981 -3.4	1981 -3.7
1982 -3.0	1982 -3.3
1983 -2.8	1983 -3.2
1984 -2.5	1984 -2.6

Other projections (1985-95)	
EPRI	2.00%
Electricity Policy Project	2.65%
Electrical World	2.85%
EIA	3.25%
Spangler and Wright	4.00%
Siegel and Sillen	5.00%

SOURCES: Summer peak, net energy, and average annual 10-year growth rate forecasts are from North American Electric Reliability Council (NERC), *Electric Power Supply and Demand, 1984-1993* (Princeton, NJ: NERC, 1984). Other projections (1985-95) are drawn from: Electric Power Research Institute (EPRI), "U.S. Energy for the Rest of the Century," Workshop Proceedings, Oct. 25-26, 1983, Palo Alto, CA; U.S. Department of Energy (DOE), Energy Information Administration (EIA), *Annual Energy Outlook 1984* (Washington, DC: U.S. Government Printing Office, January, 1985), DOE/EIA-0383(84); "35th Annual Electric Utility Industry Forecast," *Electrical World*, vol. 198, No. 9, September 1984, pp. 49-56; U.S. Department of Energy (DOE), Report of the Electricity Policy Project, *The Future of Electric Power in America: Economic Supply for Economic Growth* (Washington, DC: National Technical Information Service, June 1983), DOE/PE-0045; John Siegel and John Sillin, "The Coming Power Boom: An Assessment of Electric Load Growth in the 1980's," testimony presented to the Nuclear Regulatory Commission, November 1984; and Gordon L. Spangler and Vincent P. Wright, "Another Look At growth In Demand for Electricity," *Public Utilities Fortnightly*, vol. 113, No. 9. Apr. 26, 1984, pp. 25-28

Fiqure 3-4.—National Average Fossil Fuel Prices Paid by Electric Utilities[a]



[a]Prices are expressed in nominal dollars.
SOURCE: Energy Information Administration, *Thermal-Electric Plant Construction Cost and Annual Production Expenses—1980* (Washington, DC: U.S. Government Printing Office, June 1983), DOE/EIA-0323(80).

ting, and construction process of new powerplants as well as to rapidly rising per kilowatt costs of these plants, particularly coal and nuclear plants as shown in figure 3-7.

Increased Financing Costs

Since the electric utility business is the most capital-intensive in the American economy (see figure 3-8), its financing costs are particularly sensitive to inflation. Inflation has become an important parameter in the cost of plant construction as a consequence the large size and long leadtimes of new coal and nuclear plants.

Long-term debt, available at around 6 percent in the 1960s, more than doubled in cost by 1980.[7]

Equity capital for investor-owned utilities also became more costly; with earnings falling relative to cost, a utility must issue stock to maintain prescribed debt-equity ratios in order to continue borrowing. With lower earnings, however, new stock issues have diluted the value of existing shares to the point where, in 1983, almost half of the hundred largest utility stocks traded at below book value. This situation has improved substantially since early 1983 (see figure 3-9) and in early 1985 many utility stocks are once again trading above book value.[8]

Decreased Demand Growth

With dramatically increased costs in the electric utility business over the last decade, particularly in financing and fuel, in the mid-1970s many utilities for the first time in many years sought higher rates. Utility commissions generally granted relief (see table 3-1), however, the response of consumers was swift but unprecedented.[9] Demand growth dropped dramatically in the 1970s to less that 2 percent (see figure 3-10), although there were wide variations in this trend throughout the United States (see chapter 7). The price elasticity of demand was underestimated by many utilities and these utilities were often unwilling or unable to revise their construction plans made in the late 1960s and early 1970s. The result was decreased net revenues and excess generating capacity for most utilities, further eroding their financial performance (the reserve margin for electric utilities rose from about 20 percent in the early 1970s to over 30 percent in late 1970s, and to 35 percent in 1984).

Effect of Eroded Financial Performance

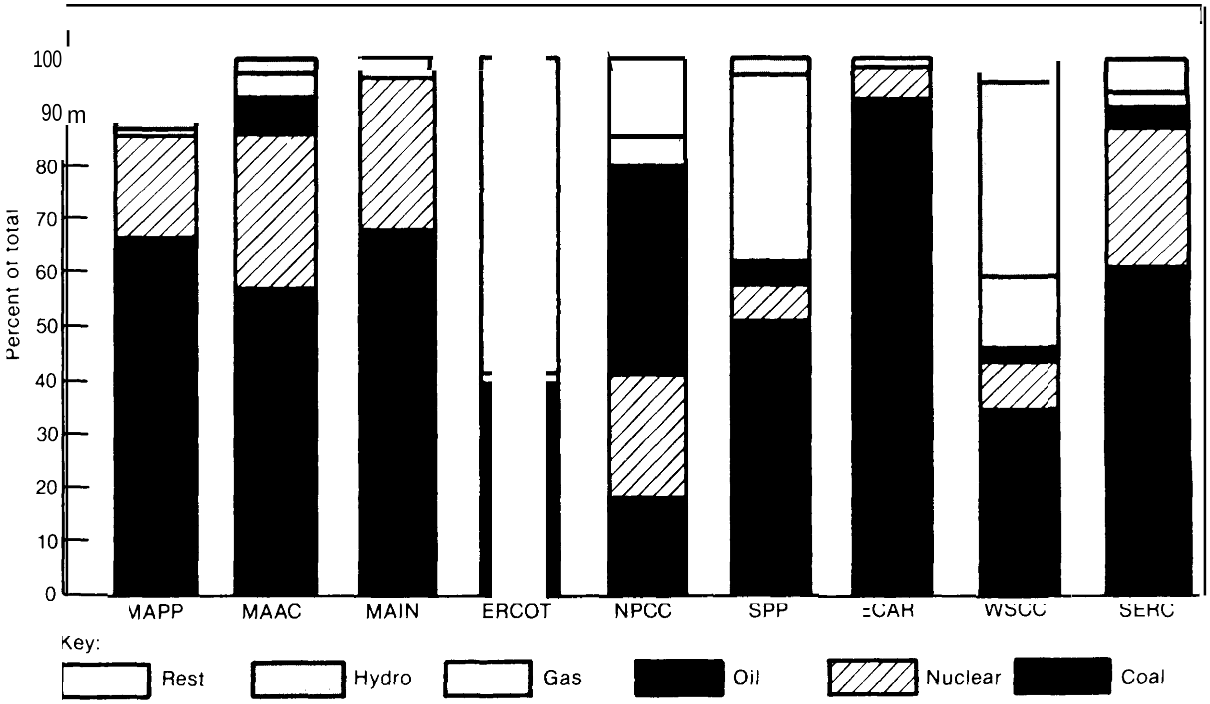
The decrease in electric utility earnings per share relative to other industries in the 1970s was

[7]An investor-owned electric utility today requires about $2.86 of investment per dollar of annual revenue compared with a dollar or less of investment per dollar of revenue for manufacturing industries; the electric utility industry (investor-owned) in the United States accounts for one-tenth of all new industrial construction in the country, a third of all corporate financing, and almost half of all new common stock issuances among industrial corporations; see S. Fenn, *America's Electric Utilities: Under Siege and in Transition* (New York: Praeger Publishers, 1984).

[8]The market-to-book ratio (used in figure 3-9) can, however, sometimes be a misleading indicator; see M. Foley, "Electric Utility Financing: Let's Ease Off the Panic Button," *Public Utilities Fortnightly*, vol. 111, No. 1, Jan. 6, 1983, pp. 21-29.

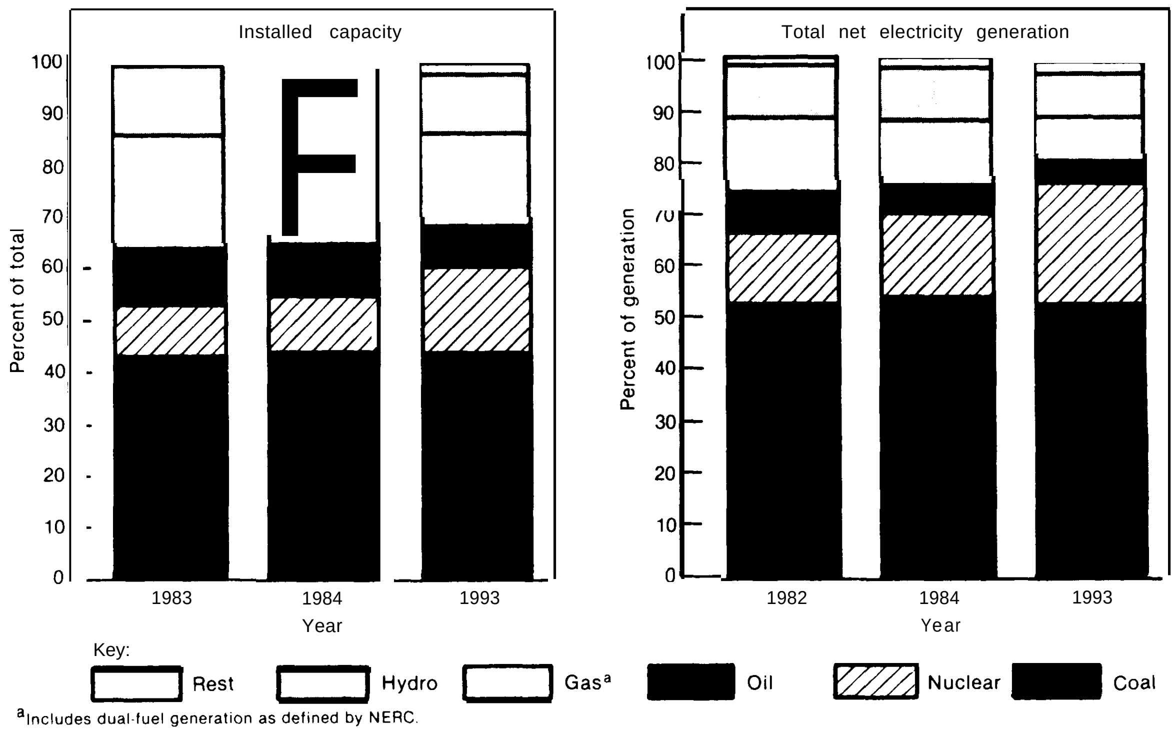
[9]Even though the real costs of electricity compared to oil and gas, for example, did not increase substantially, the changes in demand growth were just as dramatic.

Figure 3-5.— Regional Net Generation of Electricity by Fuel Type, 1984



SOURCE: Office of Technology Assessment, using data from North American Electric Reliability Council (NERC), *Electric Power Supply and Demand, 1984-1993* (Princeton, NJ: NERC, 1984).

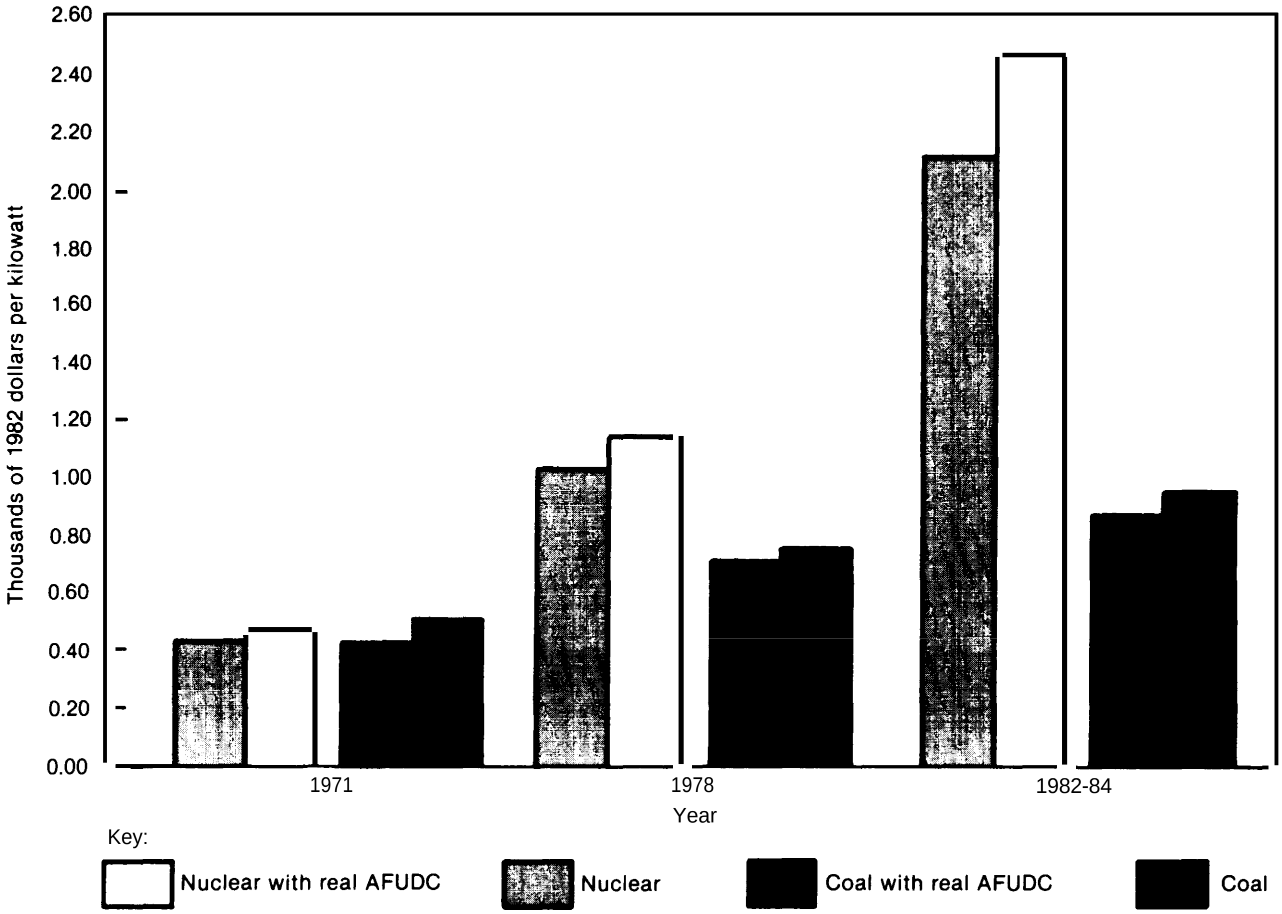
Figure 3-6.—U.S. Generation Mix by Installed Capacity and Electricity Generation



[a]Includes dual-fuel generation as defined by NERC.

SOURCE: Office of Technology Assessment, from data presented in North American Electric Reliability Council (NERC), *Electric Power Supply and Demand, 1983-1992* (Princeton, NJ: NERC, 1983); and NERC, *Electric Power Supply and Demand, 1984-1993 (Princeton, NJ: NERC, 1984).*

Figure 3-7.—Electric Powerplant Cost Escalation, 1971-84



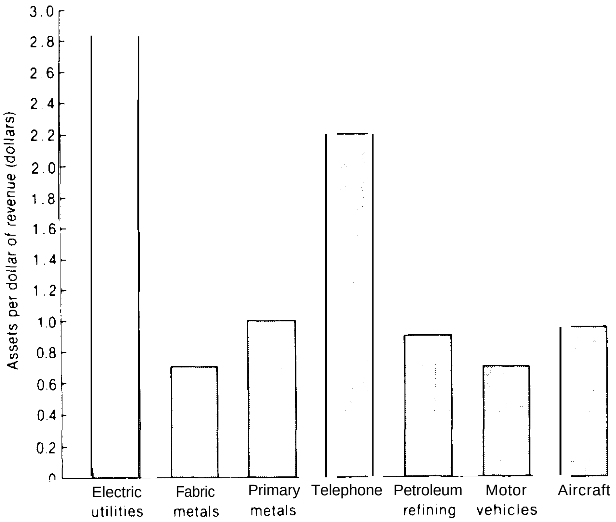
SOURCE: Charles Komanoff, *Power Plant Cost Escalation* (New York: Komanoff Energy Associates, 1981); and Charles Komanoff, "Assessing the High Costs of New Nuclear Power Plants," *Public Utilities Fortnightly*, vol. 114, No. 8, Oct. 11, 1984; construction costs do not include real AFUDC, i.e., they are based on actual construction times and real (net-of-inflation) interest rates.

a decrease in quality as well as quantity. In particular, since most utility commissions do not permit a return on any investment costs from a powerplant until it actually is in service, most utilities are permitted only to account for construction costs as an "Allowance for Funds Used During Construction"(AFUDC) and apply them to the rate base when the facility is placed in "used and useful" service. Hence, AFUDC earnings appear as part of a utility's stated earnings but, of course, they are not current revenues at all, only paper earnings. As a result, the higher the fraction of total earnings attributed to AFUDC, the lower the quality of those earnings. More recently, the practice of allowing some of the costs associated with "Construction Work in Progress" (CWIP) to be applied to the utility rate base prior to completion has been permitted by some utility commissions. The issue of allowing CWIP in the rate base is discussed in more detail in chapter 10. Today, over a half of the total earnings nationally by investor-owned utilities is AFUDC (see figures 3-11 and 3-12).

The general deterioration of financial performance of utilities has strained stockholder confidence. Indeed, in an effort to maintain this confidence many utilities have actually borrowed at short-term high interest rates to pay out dividends to shareholders.lo Likewise, the consistently high

[10]Perhaps a Milestone in recent utility history was Consolidated Edison's missed dividend payment in 1974 (see Foley, op. cit., 1983); more recently missed dividends by Public Service of New Hampshire, Consumers Power, and Long Island Lighting Co. are signaling concern to investors.

Figure 3-8.–Capital Intensity of Electric Utilities, 1982



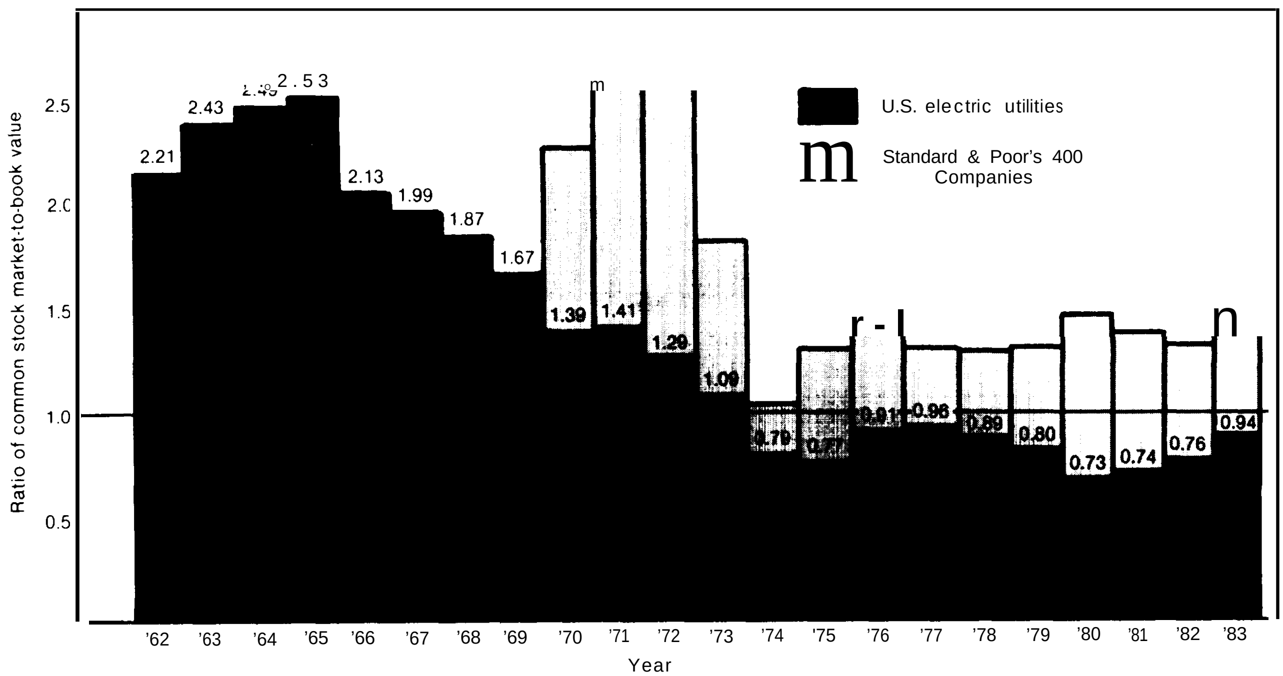
SOURCE: Bureau of the Census, U.S. Department of Commerce, "Quarterly Financial Report for Manufacturing, Mining and Trade Corporations," 4th quarter, 1982.

average utility bond ratings (AAA or Aaa) in the 1950s and 1960s fell to an average of A and below in the 1970s and to in the 1980s (see figure 3-1 3). Again, these ratings have increased since 1983, but remain below the 1960s' levels. And, it did not go unnoticed by investors that the largest municipal bond default in American history occurred within the electric power industry in 1983, when the consortium of utilities known as the Washington public Supply System defaulted on $2.25 billion of bonds on two nuclear powerplants. Many of the important financial indicators are summarized in table 3-2.

Financial Impacts of the Nuclear Experience

Beginning in 1983, the difference in financial performance between utilities involved in nuclear construction programs and those who are not has became particularly apparent. It is reflected, for example, in stock price—see figure 3- I 4. Since early 1983, the market-to-book ratio for the industry as a whole has risen substantially, but utilities involved in major nuclear projects have lagged behind. For nearly half of the industry currently involved in nuclear construction programs, the status of these projects and the economic reg-

Figure 3-9.— Electric Utility Market to Book Ratios, 1962-84



SOURCES: Marie R. Corio and Alice E. Condren, "Utilities-Electric: Basic Analysis," Standard & Poor's *Industry Surveys*, Mar. 1, 1984; and U.S. Congress, Office of Technology Assessment, *Nuclear Power in an Age of Uncertainty* (Washington, DC: U.S. Government Printing Office, February 1984), OTA-E-216.

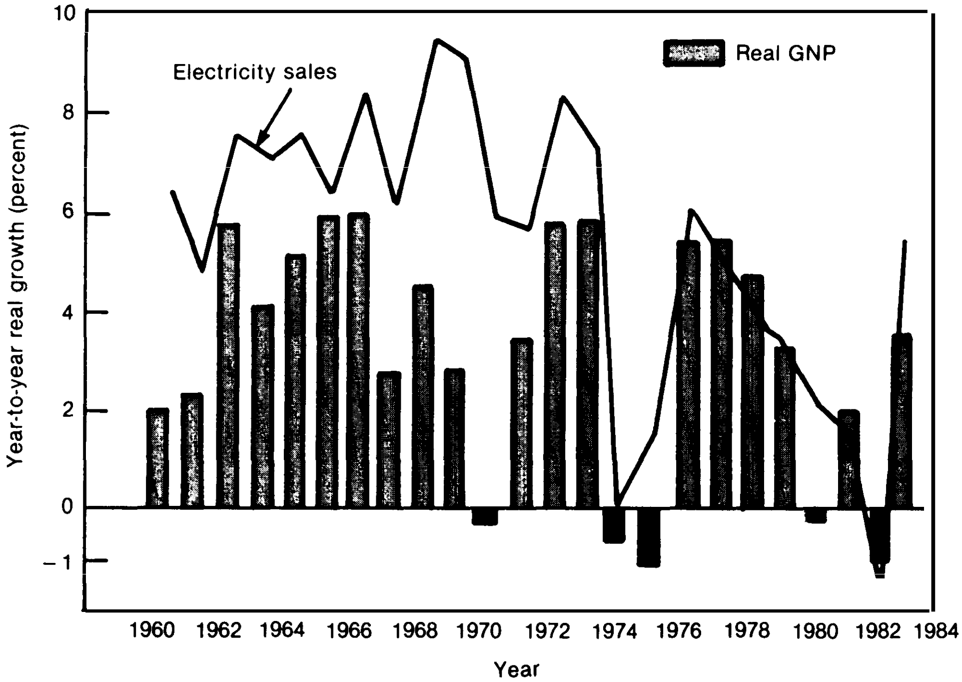
Table 3-1 .—Electric Utility Rate Applications and Approvals, 1970-84 (millions of dollars)

Year	Number of rate increases filed	Amounts requested	Amounts approved	Percent approved
1970	80	$ 797	$533	33.1
1971	113	$ 1,368	$826	39.6
1972	110	$ 1,205	$853	29.2
1973	139	$ 2,125	$1,089	48.8
1974	212	$ 4,555	$2,229	51.1
1975	191	$ 3,973	$3,094	22.1
1976	169	$ 3,747	$2,275	39.3
1977	162	$ 3,953	$2,311	41.5
1978	154	$ 4,494	$2,419	46.2
1979	178	$ 5,736	$2,853	50.3
1980	254	$10,871	$5,932	45.4
1981	237	$11,902	$8,341	29.9
1982	234[a]	$11,023	$7,629	30.8
1983	185	$12,783	$5,370	58.0
1984	61[b]	$ 4,900	$2,267	53.7

[a]Also includes two rate decreases.
[b]Through June 30, 1984.

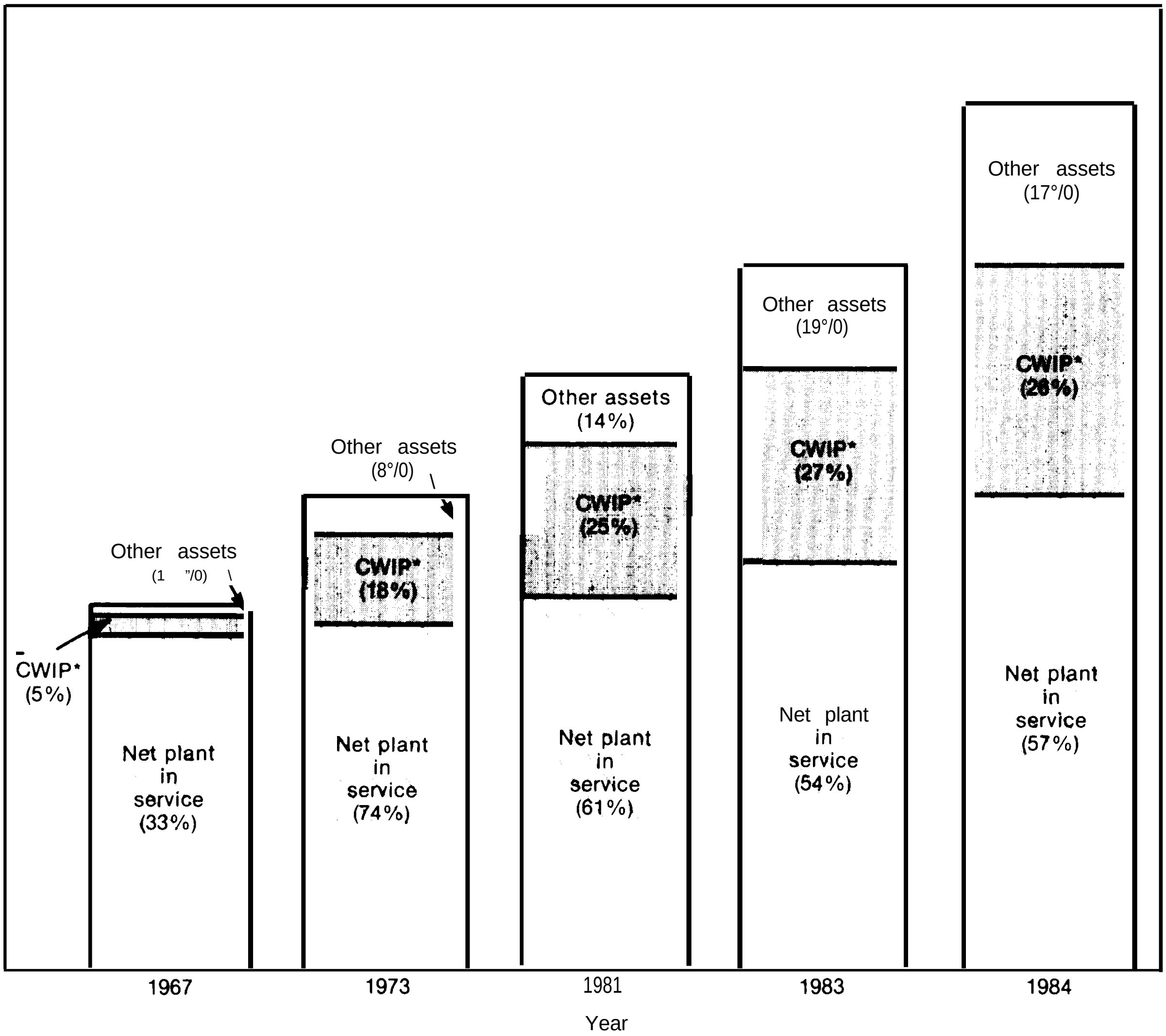
SOURCE: Edison Electric Institute (EEI), *Statistical Yearbook of the Electric Utility Industry/1983* (Washington, DC: EEI, December 1984).

Figure 3-10.—Real GNP Growth and Electricity Sales Growth Rates, 1960-84



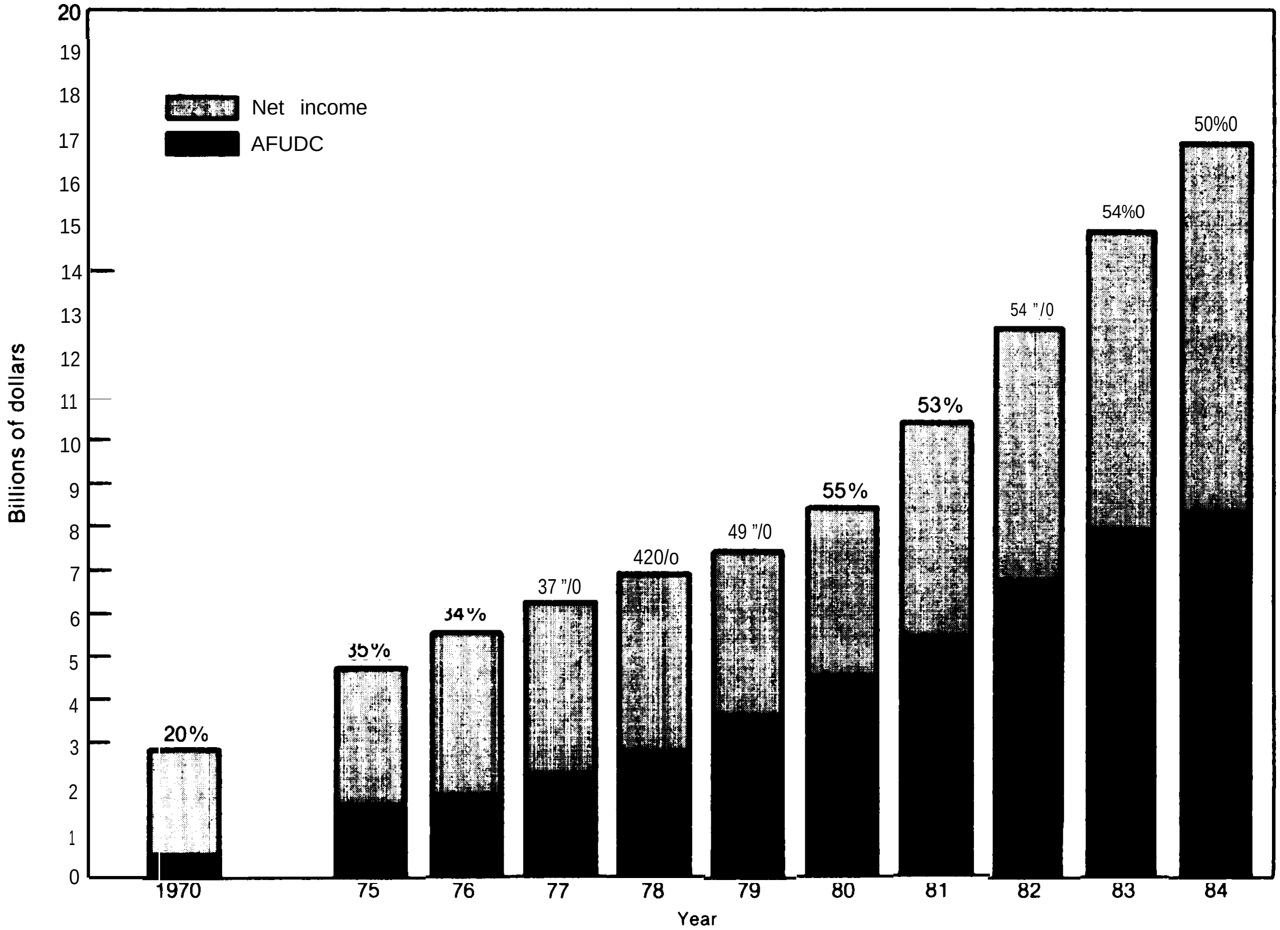
SOURCES: Craig R. Johnson, "Why Electric Power Growth Will Not Resume," *Public Utilities Fortnightly*, vol. 111, No. 8, Apr. 14, 1983, pp. 19-22; and Edison Electric Institute (EEI), *Statistical Yearbook of the Electric Utility Industry/1983* (Washington, DC: EEI, December 1984).

Figure 3-11.—CWIP As a Percentage of Total Investment



SOURCES: Edison Electric Institute (EEI), *Statistical Yearbook of the Electric Utility Industry/1983* (Washington, DC: EEI, December 1984); and Energy Information Administration, *Statistics of Privately Owned Electric Utilities, 1981 Annual (Classes A and B Companies)* Washington, DC: U.S. Government Printing Office, June 1983), DOE/EIA-0044(81)

Figure 3-12.—AFUDC As a Percentage of Total Earnings[a]



[a]Net income available for common stock.

SOURCE: Edison Electric Institute (EEI), *Statistical Yearbook of the Electric Utility Industry/1983* (Washington, DC: EEI, December 1984).

ulatory response to cost overruns, plant abandonments, and excess capacity if the plants are completed, will weigh heavily on these utilities' financial performance over the next decade. Despite the fact that some utilities have demonstrated that the difficulties with nuclear technology are not insurmountable,[11] OTA concluded last year that:

> Without significant changes in the technology, management, and the level of public acceptance, nuclear power in the United States is unlikely to be expanded in this century beyond the reactors already under construction.[12]

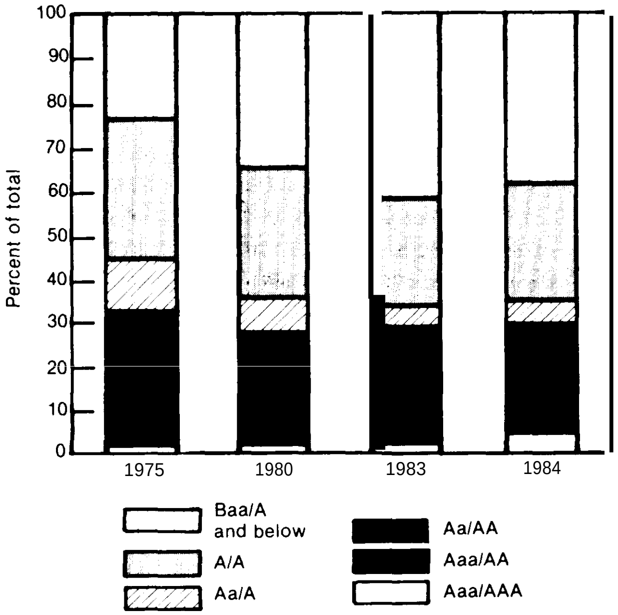
Moreover, if utility commissions consider generating reserve margins excessive, they may not include all or part of expenditures in the rate base for some plants currently under construction.

The consequences of economic regulatory treatment of such plants could range from utility bankruptcies to large rate increases, often referred to as "rate shock" for customers. Such decisions will bring the issue of the ratepayers' versus stockholders' interests into sharp focus over the next decade; indeed many alternative proposals

[11]The 85 nuclear plants operating in the United States today generally have an economical and reliable operating history; this is reinforced by the 227 nuclear plants now operating in foreign countries (a total of 531 plants are now operating, on order or under construction worldwide); see E. Meyer, et al., "Financial Squeeze on Utilities: Who Really Pays," *Public Utilities Fortnightly*, vol. 114, No. 12, Dec. 6, 1984, pp. 31-35.

[12]OTA, *Nuclear Power in an Age of Uncertainty*, op. cit., 1984.

Figure 3-13.— Electric Utility Bond Ratings,
1975-84



SOURCE: Salomon Brothers, Inc., *Electric Utility Quality Measurements—Quarterly Review*, New York, Jan. 3, 1984, and *Electric Utility Monthly*, Mar. 1, 1985.

for bringing large plants into the utility rate base are currently under intense debate.[13] Such issues are discussed in more depth later.

And finally, management of nuclear powerplant construction projects in the utility industry has been very uneven. Problems have occurred in all phases of nuclear construction programs from project design through quality control and cost control .14

Summary

The current state of affairs in the electric utility industry is one of considerable uncertainty over future demand growth, powerplant costs, and cost of capital. As a result, few utilities are willing to increase their investment risk and many have canceled or at least deferred large-scale, long lead-time construction programs. And interest by the industry in alternatives to the traditional strategy of building conventional large-scale generation plants is growing. *In* particular, these akernatives include intensified load management and conservation (either through direct load control or indirectly through the rate structure); rehabilitation of existing generating plant; and increased interconnection with neighboring utilities. Another alternative being considered is construction of smaller, and possibly decentralized, generation facilities that permit more flexible tracking of demand growth and reduced exposure to inflation and capital market fluctuations; more-

[13]See, for example, National Science Foundation, Division of policy Research and Analysis, "Workshop on Alternative Electric Power Plant Financing and Cost Recovery Methods, " Washington, DC, May 7, 1984.

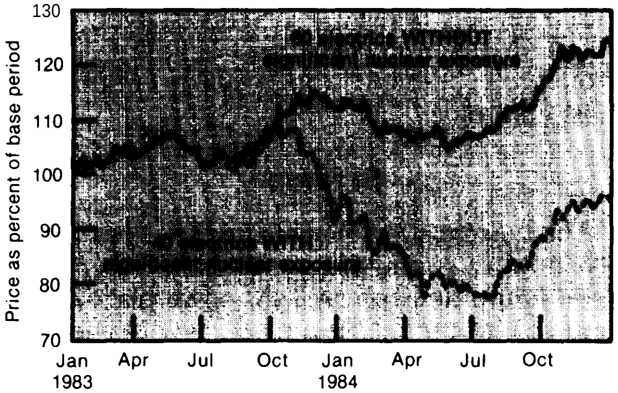
[14]See, fo,example, James Cook, ''Nuclear Fol lies, " *Forbes,* vol. 135, No. 3, Feb. 11, 1985, pp. 82-1 00; and OTA, *Nuclear Power in an Age of Uncertainty,* op. cit., 1984.

Table 3-2.—Financial Condition of Electric Utilities, 1952-84

Characteristic	"Golden age" 1952-66	"Transition" 1966-73	"Hard times" 1973-75	"Recovery" 1980	"Present" 1984
Ratio of internally generated funds to capital expenditures	0.8	0.5	0.3	0.42	0.42
Interest coverage ratio (pretax)	>5.0	3.0	2.4	3.0	3.38
Interest rate (°/0)	<4.6	6.0	8.5	15.27	10.79
Inflation rate (°/0)	1.25	4.5	8.0	13.5	3.5
Common stock price (o/o of book value)	250	150	95	73	95
Construction activity initiated	Average	Heavy	Cutbacks	Increased cutbacks	Very little
Electric rates	Decreasing	Steadily increasing	Accelerating	Increasing	Still increasing
Average return on equity (o/o):					
Including AFUDC	13	12	11	11.4	13.9
Excluding AFUDC	12	9	7.2	7.4	7.35

SOURCES: Rand Corp., *Electric Utility Decision Making and the Nuclear Option* (Santa Monica, CA: Rand Corp., 1977); Edison Electric Institute (EEI), *Statistical Yearbook of the Electric Utility Industry/1983* (Washington, DC: EEI, December 19S4); and Marie R. Corlo and Alice E. Condren, "Utilities-Electric: Basic Analysis," Standard and Poor's *Industry Surveys,* Mar. 1, 1984.

Figure 3-14.—Stock. Price Performance of Nuclear and Nonnuclear Utilities



SOURCE: Salomon Brothers, Inc., "The Outlook for Electric Utilities in 1985," *Electric Utilities: Stock Research*, New York, Jan. 7, 1985, p. 4.

over, the smaller facilities enter the rate base more quickly. Also, utilities are increasingly interested in the potential contribution of new generating technologies which use both conventional and renewable energy resources. The question is how utilities will incorporate the characteristics of these new technologies into both their planning and operations, because they are generally quite different from those of conventional generating alternatives. In addition, nonutility owners are likely to play an increasingly crucial role in the application of these technologies.

The next section reviews the traditional decisionmaking process in the electric utility industry and the forces that are changing that process. Of particular importance to the industry over the next two decades will be the ability of any given utility's management to answer the following questions:

- Are the benefits of smaller scale, shorter lead-time plants—their lower financial risk, short-term financial sustainability, and greater flexibility in filling unpredicted demand—compelling enough to consider them more carefully as an alternative to conventional large-scale, long lead-time plants?
- If the benefits of smaller, shorter lead-time plants are considered sufficient along with other benefits such as increased efficiency or reduced emissions, what conventional small-scale alternatives and what unconventional new technologies will be considered? To what degree will use of conventional alternatives preclude significant use of new technologies?
- If unconventional new technologies are perceived as potentially important in a utility's future resource plan, what institutional changes might be necessary to accommodate these technologies? Will nonutility ownership be encouraged? How?

INVESTMENT DECISIONS BY ELECTRIC UTILITIES: OBJECTIVES AND TRADE-OFFS

Introduction

in the most general terms, the principal objectives of utility decisionmakers are to: 1) ensure that system reliability is maintained, 2) minimize their ratepayers' burden over time, and 3) maintain the financial health of their companies. Any decision analysis of investments must address these objectives. Of increasing importance, particularly in evaluating the potential for new technologies, is the degree of uncertainty affecting the company's future demand, cost of service, and performance. Accounting for this uncertainty is becoming a much more important component in the decision making process of most utilities.

Investment Decision Objectives

Maintaining System Reliability

The first objective—maintaining system reliability—is often evaluated in terms of Loss of Load Probability (LOLP).[15] A prescribed level of LOLP is traditionally imposed on the utility's system planning function as a fixed constraint, e.g., one day in ten years the utility will be unable to meet its entire load. System planners then statistically

[15]Other measures are reported in General Electric CO., *Reliability Indices for Power Systems,* final report prepared for Electric Power Research Institute (EPRI) (Palo Alto, CA: EPRI, March 1981), EL-1773, RP1 353-1.

analyze peak demand predictions, at full as well as partial outage estimates of their generation and major transmission facilities, in order to project reserve margins required to meet the LOLP constraint.

The critical uncertainties in this reliability analysis include: 1) the annual peak demand forecast, 2) scheduled and forced outage occurrences of needed generating units, 3) the power output of needed generating units, 4) the on-line dates of any new generating capacity that may be planned for the period in question, and 5) the availability of purchased power. Other factors such as load management or conservation efforts and dispersed sources of generation, e.g., cogeneration, add an additional element of uncertainty to the utility's reliability analysis. (See chapter 6.) This is because there is uncertainty regarding the extent to which conservation will moderate electricity demand and load management will alter demand patterns. Further, there is uncertainty about the market penetration that will be achieved by load management devices and by dispersed sources of generation. There is also uncertainty about their reliability.

In recent years, the traditional treatment of reliability as a fixed constraint—the prescribed LOLP level described earlier–is being called into question. In particular, the trade-off between total cost and quality of service is becoming an increasing concern.[16] The argument being advanced is that electricity should be treated more as a commodity in a segmented market (different customer classes), one aspect of which is quality of service which should be reflected in the commodity price. The current debate, therefore, centers around whether electricity should be available at a uniformly high level of reliability or at increasing degrees of reliability for increasing price levels.

Minimizing Electricity Rates

The second objective of utility decisionmakers is to minimize their electricity rates. They must show their efforts to achieve this objective in their applications for changes in rates to State public utility commissions. Generally accepted ratemaking practices are discussed in chapter 8 (box 8A). The objective of minimizing rates is often measured in terms of revenue requirements or the total cost per kilowatt-hour of electric energy generated. The principal cost elements to be considered when meeting this objective are:

1. fixed costs associated with the recovery of capital invested in generation, transmission and distribution facilities;
2. fixed and variable production costs associated with operation, maintenance and fuel expenses for supply facilities; and
3, overhead costs associated with general administrative expenses and working capital allowances.

In order to compare lifetime rate requirements of different generating technologies, utilities project, over the lifetime of each plant, each component of cost–return on capital, debt service cost, fuel and operating cost, and share of overhead–and then they apply a discount rate to each year's costs to calculate a levelized annual cost. Utility decision making is complicated by the fact that plants with the same levelized cost can have very different year-to-year costs, and that utility rates are not set according to levelized cost but projected actual costs. During times of high inflation and high interest rates, the return on capital and the cost of capital-expensive plants is concentrated in the early years of a plant's life. For fuel-expensive plants the opposite is true–the year-to-year cost is initially low but increases over time. The implications of such trade-offs are discussed in more detail in chapter 8.

Maintaining Corporate Financial Health

The third objective of utility decision makers—to maintain the financial health of their companies—is typically assessed in terms of some key parameters such as growth in earnings, debt service coverage ratios, and return on common equity, System planning decisions which satisfy the two objectives discussed earlier (i. e., maintaining system reliability while minimizing ratepayers' burden) are also evaluated in terms of their impact, over time, on these measures of corporate financial health.

16 For example, see M. Telson, "The Economics of Reliability for Electric Generation Systems, " *Bell Journal of Economics, vol. 5, No. 2,* autumn 1975, pp. 679-694.

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Since the electric utility business is so capital-intensive, it relies heavily on its ability to raise capital from debt and equity sources. The availability and cost of this capital depends, to a large degree, on a utility's financial health as evaluated by security analysts and investment houses.

When evaluating a utility's financial health, these analysts weigh a wide range of qualitative and quantitative factors (see table 3-3). They seem, though, to emphasize five quantitative factors:

1. earnings protection—debt coverage,
2. leverage–equity share of total capitalization,
3. cash flow and earnings quality—share of AFUDC in total earnings,
4. asset concentration—shares of generating capacity compared to shares of the rate base, and
5. financial flexibility .17

In addition, they generally consider five qualitative factors:

1. prospects for demand growth in the service territory,
2. diversity of fuel supply,
3. quality of management,
4. operating efficiency, and
5. regulatory disposition.

Variations Among Utilities and Conflicting Objectives

Prior to the early 1970s, maintaining reliability was treated as a prescribed constraint and utilities generally had little trouble earning their allowed rate of return while achieving steady reductions in the cost of electricity, as discussed earlier. In other words, the three investment objectives could in effect be simultaneously pursued with little conflict, and the process just described generally explained utility investment decisions quite well, at least with respect to technology choice.

[17] Thomas Mockler (Standard & Poor's), "Workshop on Investment Decisionmaking in Electric Utilities," sponsored by U.S. Congress, Office of Technology Assessment, Washington, DC, Apr. 17-18, 1984.

Table 3.3.—Elements Considered in the Utility Financial Rating Process

Economic analysis of service territory:
Population
Wealth
Employment
Size of service area and outlook
Historic and estimated load growth
Demand and energy sales

Type ***of system:***
Self generation
Distribution
Combination
Wholesale and bulk power

Facilities:
Fuel mix, cost, availability, and price
Capacity and reserve
Operating cost
Operating ratio
Dispatching strategies

Capital improvement plans:
Realistic construction cost estimates
Alternatives to own construction

Rate structure:
Likely regulatory climate
Comparative rates
Ability to adjust

Bond security:
Revenues
Debt service reserve
Contingency fund
Capitalized interest
Rate covenant
Additional bonds covenant
Power contracts
Asset concentration

Key ratios:
Environmental concerns
Net take-down
Interest coverage
Debt service coverage
Debt service safety margin
Debt ratio
Interest safety margin
Percentage AFUDC
Percentage internal cost generation

Glossary for financial ratios:
1. *Operating ratio:* operating and maintenance expenses (excluding depreciation) divided by total operating revenues.
2. *Net take-down*: net revenues (gross revenues less operating and maintenance expenses) divided by system gross revenues.
3. *Interest coverage*: interest for year divided into net revenues available for debt service.
4. *Debt service coverage*: principal plus interest requirements for year divided into net revenues available for debt service.
5. *Debt service safety margin*: system gross revenues less operating and maintenance expenses and less current debt service divided by system gross revenues.
6. *Debt ratio*: net debt (gross debt as shown on balance sheet less bond principal reserve) divided by sum of net utility plant plus net working capital.
7. *Interest safety margin*: gross revenues less operating and maintenance expenses and less current interest for year divided by system gross revenues.

SOURCE: Standard & Poor's, "Standard & Poor's Bond Guide for 1983, " 1983.

The actual implementation of a decisionmaking process varies across utilities, but there appears to be little difference among utilities in the generally accepted practices for making decisions. The differences, rather, are mostly in characterizing the alternatives to be considered. A recent survey of utility decision making[18] reported that, in spite of the wide diversity of types of firms in the industry (see box 36),

> there is a high degree of uniformity in the Plant investment decision making practices followed by U.S. electric power firms, both public and private, as well as other regulated utilities.

In chapter 8 the analytical tools routinely used by utilities in making investment decisions are discussed. Also discussed are the differences among utilities, particularly with respect to differences in cost of capital (considerably different, for example, between public and private utilities), in discount rates, and in attitudes toward and methods for dealing with risk.

How utilities account for risk is important because it explains in part what might otherwise be a noneconomic choice in selecting a new technology. For example, uncertainty about demand growth, long-term financing conditions, or other "state of the world" factors may prompt more severe discounting for long-term risk against long lead-time projects. This has certainly been the case in recent years in the industry. Similarly, of particular relevance to this assessment, concern over a specific technology may swing a close investment decision one way or the other. The Edison Electric Institute[19] has classified the critical, supply-option, technology risks facing utility decisionmakers, these are summarized in table 3-4.

In addition, and reflected in some of these risks, factors relating specifically to regulatory approval are of increasing concern and have prompted utilities to carry out what is often termed "short-period analysis. " In such an analysis, planners examine how specific areas of uncertainty, such as future environmental regulations or fuel availability, might affect the financial performance in the early years of a project's life.

This new, more complex investment decision environment of the 1980s has brought with it the possibility of conflicting objectives in making investment decisions. It has become possible that utilities could decide not to pursue the lowest projected lifetime cost option (minimizing rates) for future investments because of its implications for short-term financial performance (maintaining financial health). In the long run, maintaining financial integrity does indirectly affect the ratepayers' burden, but the relationship is less clear.

Perhaps to avoid such conflict, some utilities in recent years have made substantial changes in the way they make future investment decisions. For example, Pacific Gas & Electric's (PG&E) key corporate planning goals published in 1983[20] state an "adopted direction" including:

- operation within revenue and expense levels provided by rate case decisions,
- minimize capital expenditures, and
- avoid major commitments of capital to new energy supply projects.

For PG&E, this meant that "the company will not be committing capital to any major new electric supply projects, although minimal capital expenditures may result from efforts to keep options open ." Variation in how a utility sets its basic direction for resource planning depends on regulatory pressure, financial position, and, perhaps most importantly, the character of utility management. Some utilities have substantially modified their "decisionmaking" mechanisms to better accommodate uncertainty and trade-offs in investment decisions, e.g., the "short-period" analysis described earlier.

The trade-offs among future investments are likely to be a fundamental issue of debate over the next decade, and this debate's outcome could profoundly affect the deployment of new technologies as they mature. Another recent industry survey, cited earlier[21] reports that, for the

[18]G. Corey, "Plant Investment Decision-Making in the Electric Power Industry," *Discounting for Time and Risk in Energy Policy* (Washington, DC: Resources for the Future, 1982), pp. 377-403.

[19]Edison Electric Institute (EEI), *Strategic Implications of Alternative Generating Technologies* (Washington, DC: EEI, April 1984).

[20]Pacific Gas & Electric Co., *Long Term Planning Results: 1984-2004,* May 1984.

[21]Theodore Barry & Associates, op. cit., 1982.

[illegible]

industry as a whole, "avoiding any significant capital expenditures under present (financial) circumstances is a prudent business decision . . .," and while such capital aversion could result in noneconomic generation of electricity, it was viewed as the optimal strategy of least near-term risk. The degree to which new technologies are perceived to contribute simultaneously to long-term, cost-effective supply (or the equivalent in terms of demand reduction or shifts to non-peak times) as well as to short-term improved cash flow (due to shorter lead-time and smaller scale additions) could strongly influence their market penetration by the year 2000.

Table 3-4.—Technology Risks for Electric Utility Decisionmakers

1. **Technical risk:** the probability that a new generator will fail to come on-line at its anticipated capacity rating.
2. **Lifetime risk: the probability that a** new generator's lifetime will be significantly shorter than anticipated due either to technical problems or regulatory decision problems.
3. **Cost risk: the probability** that a new generation technology will cost significantly more to construct or operate than anticipated.
4. **On4ime completion risk:** the probability that a technology will not come on-line when anticipated because of technical or regulatory problems.
5. **Lead-time risk: the probability construction** end time will be longer than planned. One problem is that events change such that the probject will no longer be needed or economically viable.
6. **Obsolescence risk: the probability that a given technology** will be economically obsolete prior to its planned lifetime. This is analogous to the lifetime risk and could result from fuel cost changes or new technologies being introduced, etc.
7. **Third-party ownership risk: the probability that a genera**tor owned by a third party will become unavailable to produce electricity for any reason related to the ownership by a third party, e.g., bankruptcy of the corporate entity owning a cogeneration facility so that the steam no longer exists and the facility is uneconomic without the steam demand,
8. **Reliability and performance risk: the probability y that a par**ticular technology will be significantly less reliable than planned.

SOURCE: Modified from Edison Electric Institute (EEI), *Strategic Implications of Alternative Electric Generating Technologies* (Washington, DC: EEI, April 1984).

As utilities emerge from the financially stressed period of the 1970s and early 1980s, the tradeoffs between financial performance and the ratepayers' burden will be a subject of continuing debate that may affect the structure of the industry itself .22

The Current Context for Alternative Investments

Most utilities have been forced by economic and regulatory uncertainties to broaden the scope of their analysis of future investments, but this has not yet led, in most cases, to investment in new generating technologies.

A 1982 EPRI survey of member utilities[23] posed the question of what strategic options were considered likely in the event of limited capital availability over the next decade. Options involving new technologies fell well down the list of priorities, behind strategies such as increased conservation, deferral of retirements, rehabilitation of existing plant,[24] and increased participation in joint ownership of large conventional plants, The survey did suggest, however, that utilities are considering new technologies as an option to pursue in the event of unexpected contingencies and that "utilities revealed an increased willingness to consider a host of new technologies for generation before the end of this century. "

Some utilities[25] think that there are three major contingencies that could more or less significantly affect the relative attractiveness of new supply technologies over the next decade:

- **Sudden increases in demand growth.**—Demand growth in the United States in 1983 was 1.9 percent and in 1984 it was 4.6 percent; demand predictions for the next decade vary from 1.5 to 5 percent.
- **Major reductions in allowable pollution emissions.**—Acid rain and other legislative initiatives could alter the kinds of coal-burning technologies and fuels used over the next decade.
- **Limited availability of petroleum.–While** the shortages **and price increases** of the 1970s prompted considerable shifts away from oil in U.S. electric power production, over 10 percent of the Nation's installed capacity is still oil-fired (see figure 3-7 earlier). Any dramatic changes in oil availability will affect the rate at which oil use declines i n power generation. This issue is discussed in depth in a recent OTA assessment.[26]

22On one hand, some economists argue that a solution to the utility industry's financial problems over the long term rests in deregulating portions of the power generation side of the business: on the other hand, others (e.g., U.S. Department of Energy (DOE), Report of the Electricity Policy Project, *The Future of Electric Power in America: Economic Supply for Economic Growth* (Washington, DC: National Technical Information Service, June 1983), DOE/PE-0045) argue that agglomeration of existing firms into larger regional entities addresses the financial problems more efficiently.

23Taylor Moore, et al., Electric Power Research Institute (EPRI), Planning and Evaluation Division, "Plans and Perspectives: The Industry's View, " *EPRI Journal, vol.* 8, No. 8, October 1983, pp. 14-19

24Although AFBC retrofits of existing units involves a new technology; this option is being pursued aggressively by many utilities.

25For example, Southern Company Services, Inc., Research and Development Department, "Assessment of Technologies Useful in Responding to Alternate Planning Contingencies, " unpublished, December 1983.

26U.S. Congress, Office of Technology Assessment, *U.S. Vulnerability to an Oil Import Curtailment* (Washington, DC: U.S. Government Printing Office, September 1984), OTA-E-243.

In the more distant future three additional contingencies could change utilities' investment decisionmaking priorities:

- **Natural gas availability.–There is still considerable uncertainty in the domestic re-**source base for natural gas, although optimism is growing.[27] If reserves are significantly greater than previous estimates suggest, then natural gas might once again become an attractive fuel for electric power generation, although this would require modifications to the Fuel Use Act.
- **Dramatic changes in interest rates.–As discussed earlier,** due to the industry's capital intensity, high interest rates have caused electric utilities much financial stress. Dramatic decreases in interest rates could dampen the current interest in short leadtime, modular design technologies relative to larger central station plants; however, it could stimulate the interest of non utility producers in such technologies.
- **Significant technological advances.–Al-**though much less likely than in other industries such as communications or computers, breakthroughs in technology could improve the likelihood of utility adoption of new technology over the next several decades. The opportunities for advances in the technologies considered in this assessment are discussed in chapter 4.

In addition, changes in Federal policies such as the tax system, PURPA, and the Powerplant and Industrial Fuel Use Act could have a significant impact on investment decisions as well; such changes are discussed in chapter 10.

While at the current rate of development extensive deployment of new technologies under any circumstances is unlikely in the 1980s, the first three contingencies are likely to affect utility decision making with respect to new supply decisions; the latter three contingencies are not likely to affect utility decisions until the 1990s.

[27]OTA, *U.S. Natural Gas* Availability: Gas *Supply* Through *the Year* 2000, op. cit., 1985.

Tradeoffs in Allocated Investments and Strategic Planning

In light of economic and regulatory uncertainties surrounding the industry, many utilities are now considering, along with traditional central station powerplants (including joint ventures in such plants with other utilities), such options as dispersed generation, increased levels of purchased power, load management (or other end-use related actions), diversification into entirely new businesses (see figure 3-1 earlier), and new generating technologies as possible investments.

With an expanded spectrum of investment alternatives along with an uncertain decision environment, the problem then becomes one of comparing options that differ considerably in terms of production characteristics as well as in terms of financial risk and return; La for example, how does one compare a kilowatt of peak-load reduction achieved through load management to a kilowatt of new capacity from wind power?

If, for the moment, one takes the quality of service to be provided by a given utility as a prescribed constraint, as utilities have traditionally done, investment decisions hinge on the relative importance of the remaining objectives, namely minimizing the ratepayers burden and maintaining financial health. In recent years in the electric utility industry, as implied in the last section, the latter objective has taken on added complexity.

Generally, a utility strives to earn a rate of return at least equal to its cost of capital. Therefore long-term **profitability could be defined as** the **difference between the return** on equity (ROE) and the cost of capital[29] (k). Short-term cash flow implications of new investments have emerged as important concerns for many utilities in recent years, i.e., a utility must generate enough cash

[28]Discussed in detail in D. Geraghty, "Coping With Changing Risks in Utility Capital Investments," unpublished paper, Electric Power Research Institute, February 1984.

[29]If a utility's rate of return equals its cost of capital, stockholders still earn a competitive return; see D. Geraghtv, "Coping With Risk in the Electric Utility Industry: The Value of Alternative Investment Strategies," *Second International Mathematics and Computer Society (IMACS) Symposium on Energy Modeling and Simulation,* Brookhaven National Laboratory, New York, Aug. 27, 1984.

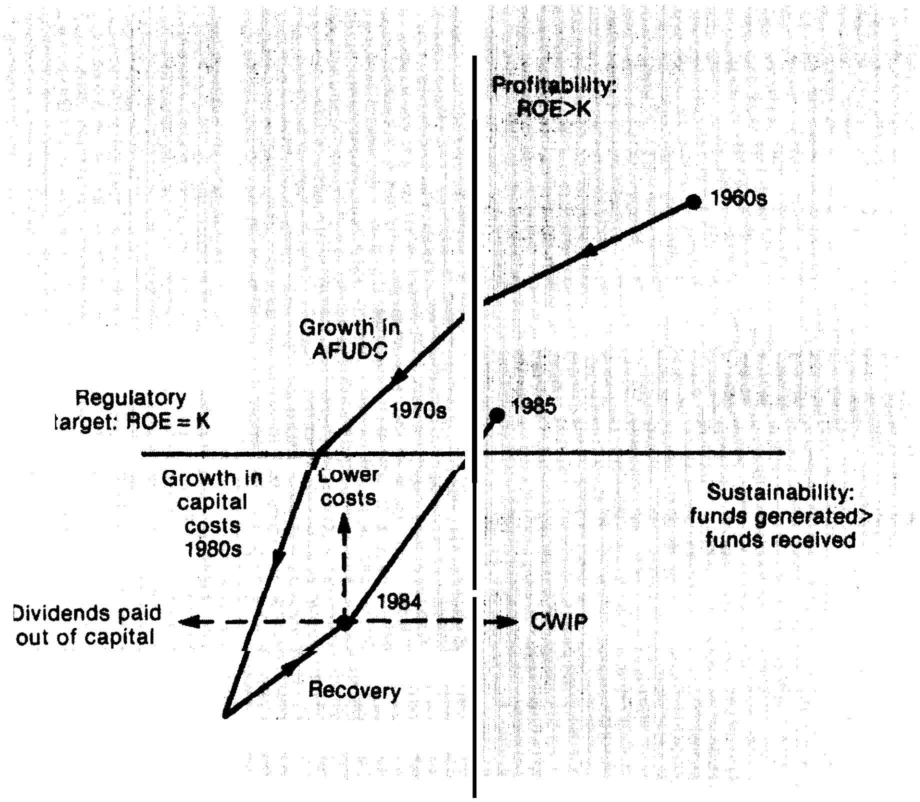
flow to maintain operations, Therefore, **sustainability could be defined as the difference between funds generated and funds used at a given time.**

The above definitions of profitability and sustainability are used in figure 3-15 to show the financial performance of utilities over the last two decades. If profitability is measured on the vertical axis and sustainability on the horizontal axis, the regulatory target is the origin, i.e., where return is equal to the cost of capital and where funds generated equal the funds received. In the 1960s, utility investments were both profitable and sustainable. With the precipitous rise in fuel prices in the early 1970s, investments became less sustainable as production costs became unexpectedly higher. With the increase in the share of earnings earmarked as funds used during construction (AFUDC), investments also became less profitable. In the *1970s* the cost of capital increased further to the point where this industry could be considered both unprofitable and unsustainable. Current utility steps to increase profitability include requests for increases in allowed rate of return and efforts to reduce cost; steps to improve sustainability include requests for CWIP costs to be included in the rate base and avoidance of new construction projects.

Financial Criteria for Investments in Capacity

Utilities concerned about both short-term sustainability and long-term profitability of their operations can evaluate investment options in terms of their impact on a number of measurable pa-

Figure 3-15.—Profitability-Sustainability in Electric Utilities



SOURCE: D. Geraghty, "Coping With Risk in the Electric Utility Industry: The Value of Alternative Investment Strategies," paper presented to the Second International Mathematics and Computer Society Symposium on Energy Modeling and Simulation, Brookhaven National Laboratory, New York, Aug. 27, 1984.

rameters that relate either directly or indirectly to sustainability and profitability. These parameters include the debt service coverage, return on equity, percent internal cash generation, and growth in earnings.

For example, an important parameter used in evaluating future cash flow implications is the debt service or interest coverage ratio which reflects the ability of the utility to repay its debt obligations and is a crucial factor in determining a utility's bond rating. s" Table 3-s demonstrates relationships between interest coverage ratios, utility bond rating, and average cost of these bonds. In this connection, year-to-year cash flow will fluctuate least when new generating plants are built in small increments and with short lead-times. Therefore, a utility aiming for a stable debt service coverage ratio could choose not to build long lead-time, large powerplants even when their cost per unit power may be less than the smaller plants because of engineering economies of scale (see chapter 8).

Prior studies give some insights into the trade-offs between short lead-time, smaller scale additions to generating capacity and long lead-time, large powerplants. Ford and Youngbloodsl show that utilities that build plants with short lead-times can maintain a lower ratio of capacity under construction to installed capacity, when year-to-year changes in demand growth are very unpredictable. A lower ratio of capacity under construction would, in turn, allow a higher debt service coverage ratio. (Short lead-times for purposes of this analysis were defined as 1 to 2 years planning and permitting and 3 to 4 years construction.)

In a similar study Behrens[32] shows that nuclear plants built in units of 400 MW to follow demand growth closely allowed debt coverage ratios to be maintained at more than 3.0 throughout the planning horizon of a sample 7,000 MW utility. On the other hand, if capacity is added in nuclear units of 1,200 MW, the debt service coverage ratio falls to below 2.0 in the year just before the plant is brought on line. The simulation used in this study assumed the smaller nuclear units cost 12 percent more per kilowatt than the larger units.

Finally, a recent Edison Electric Institute analysis[33] found that a short lead-time technology, under a specified set of assumptions, would be preferred even if its capital cost (per unit) were up to 15 percent more than conventional technology (with equal operating costs). The value of short lead-times in the face of demand uncertainty is also discussed in more detail in appendix B of that study.[34] This issue of short versus long lead-time plants is discussed in more detail in chapter 8.

[30]The interest coverage ratio accounts for as much as 80 percent of a bond rating decision; see Rand Corp., *Electric Utility Decision Making and the Nuclear Option* (Santa Monica, CA: Rand Corp., 1977) or Standard & Poor, Standard& *Poor's Bond Guide for 1983* (New York: Standard & Poor, 1983).

[31]Andrew Ford and Annette Youngblood, "Simulating the planning Advantages of Shorter Lead Time Generating Technologies," *Energy Systems and Policy*, vol. *6, No. 4, 1982,* pp. 341-374; and Andrew Ford and Annette Youngblood, "Simulating the Spiral of Impossibility in the Electrical Utility Industry," *Energy Policy*, March 1983.

Table 3-5.—Electric Utility Debt Cost and Coverage Ratio Relationships

Coverage ratio	Bond rating	Average yield
3.0-3.5	AA	11.0%
2.5-2,75	A	11 .3'?/0
2.0	BBB	12.1%

SOURCES: Standard & Poor, "Standard& Poor's Bond Guide for 1983," 1983; and L. Hyman, *America's Electric Utilities: Past, Present, and Future* (Washington, DC: Public Utilities Reports, Inc., 1983).

[32]Carl E. Behrens, "Economic Potential of Smaller-Sized Nuclear Plants in Today's Economy," Congressional Research Service paper prepared at the request of the Honorable Paul Tsongas, Washington, DC, Jan. 20, 1984, 83-621 ENR.

[33]EEI, Strategic *Implications of* Alternative *Generating Technologies,* op. cit., *1984.*

[34]The *scenario* employed assumed a utility with a 5 GW *peak* demand, 6 GW of installed capacity, a load factor of 65 percent, total embedded capital (excluding CWIP) of $9.6 billion (average yearly cost of 10 percent–real discount rate) and embedded operating costs of 3 cents/kWh. The large plant was 1,000 MW with a 7-year lead-time at a cost of $2,000/kW (1980 dollars including interest during construction); small plants were 100 MW with installed costs of $2,200/kW.

A PORTFOLIO OF INVESTMENTS: BUSINESS STRATEGIES FOR THE 1990s

Introduction

The spectrum of alternative investments currently available to many utilities was briefly outlined in the last section. This section highlights the most important considerations in each of these options. As mentioned earlier, to the extent that new generating capacity is planned at all over the next decade, the industry as a whole appears to prefer traditional conventional power generation technologies (e.g., pulverized coal-burning technologies and combustion turbines) as the mainstay for strategic planning. The EPRI Annual Industry Survey for 1982, compared with the corresponding survey for prior years, did indicate, however, that more efficient use of energy has emerged more prominently in utility strategic plans than in previous years.

The EPRI survey also revealed an increased willingness to consider new generating technologies before the end of this century, particularly in light of the future contingencies (see previous section) that could affect the viability of conventional alternatives. In some utilities where available renewable resources are particularly attractive and plentiful, alternative technologies such as solar, geothermal, and wind may contribute significantly to future resource plans, but continued development of these technologies was viewed by the survey as benefiting only a handful of utilities over the next several decades.

Strategic options such as rehabilitation of existing plant and increased purchases of energy from neighboring utilities have emerged as important alternatives for utilities in the next decade, particularly where capital is in short supply.

Overall, therefore, in considering alternative strategic options for utilities, it is important to keep in mind that new generating technologies now appear to fall well down the list of priorities for most utilities, though interest in them is increasing as utilities plan for dealing with future uncertainty.

The business strategies of U.S. utilities, while actually a continuum, can be classified roughly into four basic, but not exclusive, categories:[35]

- **Modified grow and build strategy .-A number** of utilities have continued to view completion of large nuclear and coal plants initiated in the 1970s **as their best option.** Allowing for changes in the fuels used in generation, this is a continuation of the strategy of virtually the entire industry since its beginning. Some utilities, confident of renewed demand growth in the 1990s, **are planning for continued expansion.**
- **Capital minimization.–Many utilities in the United States are now reacting to the current regulatory and financial climate in the industry with a strategy of minimizing capital expenditures by canceling plants both planned and currently under construction, increasing use of purchased power, participating in joint ventures if construction is necessary, selling existing capacity, rehabilitating existing plant, and increasing attention to load management. This strategy is designed to minimize corporate risk.**
- **Renewable and alternative energy supply.– A few utilities have embarked on a strategy of significantly increasing reliance** on renewable energy sources as well as cogeneration from conventional sources in an effort to use small, modular plants to better track uncertain demand growth and reduce construction lead-times (other reasons are discussed later). The two large utilities (PG&E and Southern California Edison) that have made reliance on these sources an announced part of their strategy both come from California where renewable resources are relatively abundant and avoided energy costs are high. Many more utilities have initiated increased research and development programs in new

[35]These categories are defined by S. Fenn, *America's Electric Utilities: Under Siege and in Transition*, op. cit., 1984).

technologies (discussed later). How many of these will go on to base a significant part of their strategic planning on alternative sources is uncertain.

- **Diversification.–A majority of investor-**owned utilities have begun to diversify their business interests by investing revenues in potentially more profitable ventures outside the electric utility business (see table 3-8). While the level of expenditures in such activities is as yet very small, a large number of utilities are exploring new business ventures on a small scale in areas such as real estate, telecommunications, oil and gas exploration, and business services.

Conventional Alternatives

The industry surveys cited earlier reveal that if more capital is available to electric utilities over the next decade and if emissions requirements are not tightened, conventional pulverized coal steam plants are generally the preferred investment option for future generation. The future of nuclear power remains clouded by management and regulatory problems as well as by technical and financial uncertainties. The EPRI survey found that "business decisions on new nuclear plants will remain clouded' 'until such uncertainties are resolved. This conclusion is supported by the recent OTA assessment on the future of nuclear power as well as by others. [36]

As discussed earlier, the cash-flow drawbacks of the long lead-time, large, conventional coal and nuclear plants as well as the potential costs of overbuilding due to uncertain demand growth have prompted utility interest in designs for these conventional technologies that permit installation of smaller, modular units (200 to 500 MW rather than 800 to 1,200 MW), even at a significant capital cost premium. In addition, in planning for circumstances such as increased regulation of pollution emissions, other utilities have also become interested in other modifications of conventional coal technologies. These include limestone injection, advanced coal cleaning techniques, improved scrubbers, and others.[37] Such modifications, while generally outside the scope of the current study, could significantly affect the relative attractiveness of new technologies under all the possible future contingencies cited earlier. Considered in this assessment are advanced coal conversion processes such as fluid ized-bed combustion and integrated coal gasification/combined-cycle units.

Load Management and Conservation

One of the surveys cited earlier[38] found that 72 percent of the utilities they surveyed had initiated formal conservation programs and over two-thirds have started formal load management programs (see table 3-6). Fifty percent of these load management and conservation projects have appeared since 1980. Total investment in such programs is expected to increase dramatically over the next decade, particularly in load management. The survey suggests that "virtually the entire industry will have incorporated such activities in a formal way" (see table 3-6). Conservation options are not considered in this report but load management is discussed in chapter s.

Plant Betterment

Many utilities have found it useful to consider measures of rehabilitating existing generation capacity or improving maintenance to extend their useful lives.[39] Indeed, some studies have found a high correlation between maintenance expenditures, unit availability, and adjusted return on equity, i.e., the difference between the earned return and bond yields. @ Moreover, as life extension options are reviewed more carefully, many units operating at derated capacities, since they are approaching the end of their design lives, can be restored to their original output and more (up to 10 percent) with improved heat rates and overall efficiencies.[41] Some current researchaz

[36]OTA, *Nuclear Power in an Age of Uncertainty,* op. cit., 1984; or Scott Fenn, The *Nuclear Power* Debate: Issues and *Choices (New* York: Praeger Publishers, 1981).

[37]See the Southern CO. Services report cited earlier.

[38]Cogan & Williams, Investor Research Responsibility Center, op. cit., 1983

[39]Lee Catalano, "Utilities Eye Unit Life Extension, " *Power, vol.* 128, No. 8, August 1984, pp. 67-68.

[40]A. Corio, National Economic Research Associates, research summarized in "First Annual Maintenance Survey, " *Electrical World, vol.* 197, No. 4, April 1983, pp. 57-64.

[41]G Fried lander, "Generation Report: New Life Available for Old T/G's" and Boilers," *Electrical World, vol. 197, No. 5,* May 1983, pp. 87-96.

[42]Summary of ongoing research by Temple, Barker & Sloane, Inc. given in "Optimum Use of Existing Plant, " *Utility Investments Risk*

Table 3-6.—Conservation and Load Management Programs of Leading Utilities[a]

Company	Generating capacity 1982	Projected annual increase in demand through 1992	Program adoption date(s)	Program costs in 1982 (000)	Projected megawatts saved through 1992
TVA	32,076	2.38%	1977	57,000	4,000
Duke Power	14,526	3.87	1975	NA	2,994
Florida P&L	12,865	3.5	1980	23,000	2,100
Pacific G&E	16,319	0.9	1976/77	84,000	1,871
Carolina P&L	8,085	3.0	1981	10,600	1,750
Houston L&P	12,966	2.6	1978/80	12,500	1,700
So Calif Ed	15,345	2.0	1972	46,154	1,500
Florida Power	5,899	1.0	1980	5,000	1,500
Public Serv E&G	9,023	1.3	1982	9,000	956
BPA	0	NA	1980	86,000	802
Jersey Cen P&L	3,371	1.5	1980	9,000	800
Alabama Power	9,194	2.59	1976	1,266	800
Penn El	2,736	2.0	1973	4,200	671
Los Angeles	6,749	1.7	1976	7,876	601
Oklahoma G&E	5,359	NA	1982	NA	600
Northern States	6,162	2.0	1979	10,000	600
Metropolitan Ed	2,144	1.85	1980	1,000	485
Texas P&L	7,904	5.1	1977/81	5,100	465
Detroit Ed	9,458	2.5	1968/81	13,000	450
Arizona PSC	3,522	2.3	1977	3,230	420
Kansas City P&L	2,774	2.3	1982	NA	412
Tampa El	2,495	2.7	1980	8,000	400
Penn P&L	6,470	1.5	1983	4,700	390
Consolidated Ed	10,564	1.0	1975	440	370
Utah P&L	2,751	NA	1977	10,440	318

[a]Survey asked utilities to respond under a controlled growth scenario

SOURCE: Douglas Cogan and Susan Williams, *Generating Energy Alternatives: Conservation, Load Management, and Renewable Energy at America's Electric Utilities* (Washington, DC: Investor Responsibility Research Center, Inc., September 1983).

suggests that life extension programs could dramatically reduce future revenue requirements as well. These options are discussed in more detail in chapter 5.

Plant rehabilitation and life extension are likely to be very significant options over the next two decades for utilities with a significant fraction of aging plants. These prospects over the next two decades depend on the life times assigned to existing capacity. For example, with an assumed 30-year average plant life, over 200 gigawatts (GW) of replacement capacity will be required by the year 2000, but with an assumed 50-year life, only 20 GW would be required (see table 3-7). Overall in the United States, the prospects for plant rehabilitation or life extension are limited by the fact that over half of the U.S. generating capacity has been built since 1970. In addition, these prospects vary considerably by region (see chapter 7).

Increased Purchases

Interconnection among utilities has always been common in the electric power industry but in recent years bulk power transfers have increased dramatically. In fact, the total volume of bulk power transfers increased by a factor of 30 between 1945 and 1980 while total electricity production increased only by a factor of 10.43 In general, bulk power purchases are undertaken by a utility if the marginal cost of production in an interconnected utility is less than it would cost for the buyer to produce that power itself. The most significant increases began to occur in the early 1970s as oil prices forced many utilities

Analysis: Technical Newsletter, Electric Power Research Institute, Energy Resources Program, No. 2, February, 1984; also see H. Heiges and H. Stoll, "Benefits of Power Plant Life Extension in Today's Business Climate," *Proceedings of the American Power Conference*, 1983.

[43]U.S. Department of Energy, Energy Information Administration, *Interutility Bulk Power Transactions*, (Washington, DC: U.S. Government Printing Office, October 1983), DOE/EIA-0418.

Table 3.7.—Replacement of Powerplants: Selected Options

	Cumulative replacement capacity GW needed by:			
	1995	2000	2005	2010
If existing powerplants are retired after:				
30 years.	155	230	395	510
40 years.	55	105	155	230
50 years.	—	20	55	105
If all oil and gas steam capability is retired as follows:				
All	152	152	152	152
Half	76	76	76	76
All oil and gas capacity above 20 percent of region (3 regions).	55	55	55	55
If average coal and nuclear availability slips from *70%* to:				
About 650/o	21	21	21	21
About 600/0	42	42	42	42

SOURCE: US. Congress, Office of Technology Assessment, *Nuclear Power in an Age of Uncertainty* (Washington, DC: U.S. Government Printing Office, February 1984) OTA-E-216; this analysis shows the sensitivity to North American Electric Reliability Council data projected from 1983,

highly dependent on oil to seek lower cost power from less oil-dependent neighbors and, as a result, the ratio of power purchases and wholesale power sales to total electricity sales among utilities varies by region as discussed in chapter 7.

While there are many different types of bulk power transactions, most fall into one of three categories:

1. economy transactions that reduce operating costs by displacing the buyer's own higher cost power with lower cost power from a neighboring utility;
2. capacity transactions which permit **a** utility to claim additional generating capacity from a neighboring utility to supplement its own for a specified period of time (sometimes called firm power transactions); and
3. reliability and convenience transactions that are negotiated to improve system operation and reliability—e.g., emergency support.

Some utilities will clearly benefit over the next two decades from increased reliance on purchased power from neighbors that have excess coal-fired and hydroelectric capacity and adequate transmission capabilities, and this option is being actively pursued by utility resource planners. Moreover, Canada will be an increasingly important source of electricity, primarily hydroelectric power, for U.S. utilities in certain regions.[44] [45] The likelihood of increased bulk power transfers both within the United States and from Canada and Mexico will affect the comparative attractiveness of new generating technologies in some regions.

Diversification

Some researchers argue that diversification of electric utility investments to more profitable lines of business could greatly benefit the industry's overall performance.[46] Indeed, diversification has received increased attention across the industry as shown in table 3-8. Other studies have observed this trend as well.[47] While outside the primary scope of the current study, diversification could play an important role in the strategic planning of some utilities in the next decade since such a strategy seeks to realize so-called "economies of scope," i.e., a utility might be able to exploit existing assets to obtain cost advantages in nonutility lines of business. For example, billing and collection or engineering services for other businesses could build on the existing infrastructure already present in the utility. The regulatory response to diversification is as yet uncertain; the range of activities is limited somewhat by individual public utility commissions, the Public Utility Holding Company Act, and PURPA.

[44]Although the limitations on transmission capacity will become a major issue in the decades to come; currently, for example, New England is negotiating firm power contracts with Canada because transmission capabilities exist while links with the Ohio River Valley which has excess generating capacity are limited.

[45]International trade agreements with Canada for firm power (as opposed to economy interchanges which have been routine for many years) have recently become an important issue on both sides of the border; see Diane DeVaul, et al., *Trading in Power: The Potential for U.S./Canadian Electricity Exchange* (Washington, DC: Northeast-Midwest Institute, September, 1984); "Trading in Power: A Binational Conference on Electricity Exchange," Lake Placid, NY, Sept. 6-7, 1984; D. Hodel, "Statement on Canadian Imports of Electricity," (statement read to the Northeast-Midwest Institute Conference on Trading in Power), Sept. 6, 1984; and R. Bourassa, *Power From the North* (Scarborough, Ontario: Prentice-Hall, 1985).

[46]Edison Electric Institute (EEI), *Business Diversification Activities of Investor-Owned Electric Utilities* (Washington, DC: EEI, 1985).

[47]D. Arthur and A. Harris, "Diversification in the Electric Utility Industry," unpublished paper, Portland General Electric Co., Corporate Planning Division, Portland, OR, January 1981.

Table 3-8.—Edison Electric Institute Business Diversification Survey[a]

Venture	Percent of total
Fuel development and exploration	26
Real estate	13
Energy conservation services	8
Cogeneration and small power production	5
Appliance sales and service	5
Project management and consulting	5
Fuel transportation	5
District heating	3
Land management controls	3
Computer software sales	3

[a]Based on 296 total responses.

SOURCE: "EEI Details Utility Diversification in New Report," *Electric Light & Power*, vol. 63, No. 6, June 1985, p. 18; Edison Electric Institute (EEI), *Business Diversification Activities of Investor-Owned Electric Utilities* (Washington, DC: EEI, 1985).

Developing Supply and Storage Technologies

The range of technologies considered in this assessment that may show promise in electric power generation through the 1990s are included in table 3-9. A detailed evaluation of the probable costs and performance of these technologies is given in chapter 4. Considered here are some of the generic characteristics of these technologies that might affect a utility's decision to adopt them or might encourage nonutility investment in them.

Table 3-9.-Developing Technologies Considered in OTA'S Analysis[a]

- Photovoltaics:
  - Flat plate systems (tracking and nontracking)
  - Concentrators
- Solar thermal electric:
  - Solar ponds
  - Central receivers
  - Parabolic troughs
  - Parabolic dishes
- Wind
- Geothermal:
  - Dual flash
  - Binary (large and small)
- Atmospheric fluidized-bed combustors
- Integrated gasification/combined-cycle
- Batteries:
  - Lead acid
  - Zinc chloride
- Compressed-air energy storage (large and small)
- Phosphoric-acid fuel cells (large and small)

[a]For description see box 2A, ch. 2 and ch. 4.

SOURCE: Office of Technology Assessment

Most of the developing technologies listed in table 3-9 are small in scale relative to conventional alternatives; hence they generally have shorter lead-times and offer the following benefits:

- Modularity.–Modularity of units, both in construction and in duplication of plants at a single site, means that decisions to initiate new capacity additions can be made closer to the time the units are actually needed. As a result, there is more flexibility in both tracking highly uncertain demand growth and in bringing new capacity on line to correct for temporary undercapacity. Several of the new technologies considered in this assessment (see table 3-9) lend themselves to modular design–e.g., wind, photovoltaics, fuel cells, and IGCC. Utilities consider flexibility in periods of highly uncertain demand growth to be a primary motivation for examining new technologies.[48] Combustion turbines have traditionally been used by utilities to reduce their exposure to risk during periods of uncertain demand growth, but they involve very high operating costs and use of premium oil and gas fuels. The gas industry is, however, very optimistic about the future of combined-cycle plants using natural gas.
- **Less "rate shock."–Rate increases can be moderate with small plants or units coming on line and entering the rate** base. If demand growth is very large, however, many small plants or units will be required and "rate shock" could be even more severe since small plants or units of alternative technologies generally come at a capital cost premium. A similar rate shock through fuel adjustment clauses might be experienced with a strategy of using combustion turbines to meet such unpredicted, large demand growth.
- **Increased reliability.–Generally speaking, smaller units permit maintenance of a smaller reserve margin since individual forced outages of smaller units have less impact, although** if the system is mixed, i.e.,

[48]W. Gould, "Development of Renewable/Alternative Resources of Electric Energy," unpublished, Southern California Edison Co., Rosemead, CA, 1983.

with some large and small generators, the reserve margin must cover the possibility of a forced outage of the large units. Moreover, the potential of this benefit is complicated if the small units are dispersed source generators as discussed in chapter 6.

- **Improved financial flexibility.–The** amount of capital tied up in construction is substantially reduced by employing short lead-time technologies. Security rating agencies are concerned when a utility incurs a significant "asset concentration risk, " e.g., placing a large amount of capital at risk on a single project which could ultimately account for 50 to 60 percent or more of the utility's rate base but only 10 to 15 percent of its installed capacity.
- **Improved quality of earnings.–Less** capital tied up in construction translates into a lower level of AFUDC reported in a utility's earnings. This, in the eyes of investors, raises the quality of earnings since AFUDC is considered a "paper" earning.
- **Technology and fuel** diversity .–Diversity of fuel types and technologies employed by a utility reduces not only technological risk but also institutional risks such as the impacts of a coal strike or an oil supply disruption,

In addition, many new technologies offer environmental benefits as well as adv~ntages of fuel flexibility, increased efficiency, the potential of reduced fuel transportation costs and, in many cases, the possibility of cogeneration. Moreover, if a small-scale technology is suitable for dispersed siting near load centers, additional benefits are possible:

- **Reduced transmission requirements. -Siting closer to load centers reduces the need for transmission; large plants generally must be sited much further** away. The potential level of transmission "credit" possible in small dispersed generating units has been the subject of much research. [49]
- **Improved quality of service.-–Outages can** generally be serviced more quickly with dispersed generation available to be dispatched locally.
- **Improved area control.**—If **decentralized** sources can be coordinated with energy control centers (where power flow to load centers is controlled), the result will be better regulation of area control error and hence improved efficiency and quality of power (see chapter 6).

While all of these potential benefits are in many cases sufficiently attractive to warrant interest on the part of utilities, alternative technologies also pose complications for utility planners in addition to the risk of relying on new technology. These include:

- **Load dependence.—The uncertainty associated with impact on the system load curve of dispersed generating sources is compounded by the fraction of this generation coming from intermittent alternative energy sources such as wind, solar, and low-head hydroelectric systems. Unlike conventional sources or fossil-based dispersed sources which are largely independent of load characteristics, alternative sources are often interdependent with load due to such factors as wind** speed, solar energy flux, temperatures, steam flow, etc.
- **Nondispatchable generation and utility operations.—As mentioned earlier, nonutility or customer-owned equipment (actually** for both new as well as conventional technologies) operating under the provisions established by PURPA are not generally included in a utility's economic dispatch system. Most utilities have treated nondispatchable generation as an expected modification of the system load curve in the same manner as load management. As penetration of nondispatchable sources grows, however, utilities will need to account for them more explicitly in dispatching strategies.
- **Nonutility generation and capacity planning.—As mentioned earlier, nonutility generation has traditionally been treated as a modification to the system load curve. If significant penetration** of such generation is considered a possibility, as might be the case in a number of utilities, the capacity plan-

dgs[ee], for example, S. Lee, et al., Systems Control, Inc., *Impact of Transmission Requirements of Dispersed Storage and Generation* (Palo Alto, CA: Electric Power Research Institute), December 1979, EM-1 192.

ning process for these utilities could be affected. The attitudes of utilities toward nonutility generation varies markedly among utilities in terms of interconnection requirements and conventions for establishing of avoided cost rates. Interconnection requirements such as insurance, control and safety equipment, meters, and telecommunications equipment can all vary according to size of generating plant, approved design specifications or other factors (see chapter 6). Similarly, avoided cost rates vary according to procedures for capacity and energy credits, and availability of "payment tracking mechanisms" that permit nonutility generators to receive higher revenues in early years of the project, as is the practice at Southern California Edison. The ultimate contribution of nonutility generation to the overall U.S. power generating capacity depends on not only the performance of the technology and adequate financial incentives, but also on the evolving attitudes of utilities, especially as they apply to rates and interconnection with nonutility generation. Indeed, interconnection requirements alone can increase nonutility generation cost by over $1,000/kW for small systems.[50] Some work is now being done to incorporate nondispatchable technologies into long-term generation planning.[51]

- **Rate inequities .—The possibility of rate inequities also presents a potential problem in the case of encouragement of a large** penetration of nonutility generation. Rate requirements are estimated for various customer classes, e.g., residential, commercial, heavy industrial, etc., based on the total revenue requirements of the utility and the forecasted demand of each customer class (including time of day and cost of service considerations). A situation could arise whereupon the demand of a particular customer class is reduced by the implementation of end-use devices or third-party generation plants and, consequently, customer rates must be increased to meet fixed revenue requirements.[52] Potential rate inequities may result, particularly to those customers in an affected rate class who do not use the demand-reducing device.
- **Research and development and regulatory treatment.–As we will see** in chapter 4, most new generation technologies, today, are not yet cost competitive with conventional alternatives. For promising new technologies, part of the difference between current and mature costs represents the amortization of R&D expenditures. An often-used operational rule among many utility commissions, however, is to permit plants into the rate base only if they can generate power at less than full avoided cost.[53] The issue then becomes clear: to what extent will the less than full avoided cost benchmark inhibit the commercialization of new technologies? If such a benchmark is relaxed, to what degree should ratepayers share with the stockholders the burden of higher per unit capital costs, greater risk of lower reliability, possibility of complete plant failure, and possibility of shorter plant life associated with new technologies? Some studies suggest that relaxed treatment of the full-avoided cost benchmark is a prerequisite to significant penetration of many new technologies (at least for demonstration and early commercial units) in utilities over the next two decades.[54] This issue is discussed in more detail in chapter 10.

[50]See U.S. Congress, Office of Technology Assessment, *Industrial and Commercial Cogeneration* (Washington, DC: U.S. Government Printing Office, February 1983), OTA-E- 192; and U.S. Department of Energy (DOE), *Survey of Utility Cogeneration Interconnection Projects and Cost—Final Report* (Washington, DC: DOE, June 1980), DOE/RA/29349-01.

[51]As discussed in M. Caramanis, et al., "The Introduction of Nondispatchable Technologies as Decision Variables in Long-Term Generation Expansion Models, " *Institute of Electrical and Electronic Engineers (IEEE) Transactions,* vol. PAS-101, No. 8, August 1982, pp. 2658-2667.

[52]This phenomenon occurred in 1973-74 in San Francisco with local water utilities. Regional droughts motivated the utilities to subsidize advertising campaigns and various end-use devices for water conservation. The resulting drop in demand was of such magnitude that the utilities were put in a position of having to *increase* rates to meet their revenue requirements.

[53]L. Papay, "Barriers to the Accelerated Deployment of Renewable and Alternative Energy Resources, " unpublished, Southern California Edison Co., December 1982.

[54]Ibid.

Current Activities and Interest in Alternative Technology Power Generation

The Edison Electric Institute[55] has observed four degrees of current involvement (not mutually exclusive) in alternative technology power generation by U.S. utilities:

- **Use of alternative technologies as a substantial contributor to future resource plans.–** Some utilities which are historically highly dependent on premium fuels (and hence have a very high avoided cost rate), have significant demand growth, and have severe environmental and regulatory constraints on using conventional technologies have announced significant plans for reliance on alternative technologies. As mentioned earlier in the discussion, only two such U.S. utilities, namely Southern California Edison and Pacific Gas & Electric, have done so to date.
- Use **of alternative technologies as a response to uncertain load growth.—Some medium demand growth utilities, in response to environmental and regulatory pressures, have included alternative technologies** as "an important but small" buffer in future resource plans.
- **Use of unregulated subsidiaries for equity participation in cogeneration.-Some** financially sound utilities—e,g., Houston Lighting & Power–in areas with cogeneration potential have been permitted by utility commissions to invest capital in cogeneration ventures with industry to avoid loss of load, revenue, and earnings. This strategy is termed "reactive diversification" as opposed to "proactive diversification" which is aimed at improving stockholder return on equity.
- **Active research and development.–Many** utilities, are involved in long-term research and development with alternative generating technologies as a possible response to various contingencies discussed earlier that could limit the use of conventional generating technologies.

So far, the penetration of new technologies has been very small. A great deal has happened in the last several years, however, particularly in cogeneration. Most of this cogeneration is using conventional technology, but some are new technologies such as AFBC. In addition, wind, low-head hydroelectric, and biomass technologies are also contributing. For the technologies considered in this assessment we discuss the historical rate of development in detail in chapter 9.

[55] Edison Electric Institute, op. cit., 1984.

SUMMARY AND CONCLUSIONS

The electric utility industry has experienced a period of considerable stress in recent years due to declining electricity demand growth; dramatically increasing fuel prices, construction costs, and capital costs and heightened public demand for better control of air and water pollution and nuclear safety. The industry emerged from this period of stress with significant uncertainties, especially about future demand growth, and financially weakened. While utilities' financial health appears to be improving markedly, they are not returning to their pre-1970s business strategies.

Still facing a difficult and uncertain investment decision environment, utilities have had to expand the scope of strategic options they are willing to consider over the next several decades to include such strategies as rehabilitation of existing plant, increased purchases from neighboring utilities, increased conservation and load management efforts, diversification of investments to nonutility lines of business and, finally, a range of new generating technologies. Most utilities are only beginning to consider such alternatives to traditional large-scale, central-station, powerplants. In particular, conservation and load management are beginning to attract more attention in utility resource plans; and many utilities have plant life extension or rehabilitation projects underway. Similarly, in response to uncertain demand growth, mature smaller scale technologies are under close scrutiny. For the most part, smaller scale new technologies are under consideration primarily as a possible response to future contingencies such as oil supply disruption or imposition of stricter environmental controls on coal burning. There are a few exceptions, notably Southern California Edison and Pacific Gas & Electric in California. They have included substantial commitments to new technologies in their long-term resource plans.

To date, nonconventional technologies account for only a tiny fraction of the Nation's overall electric generating capacity, the new technologies' penetration of the market is likely to grow throughout the remainder of this decade and throughout the 1990s.

Non utility involvement in new technologies is increasing steadily under the provisions of PURPA and the rate of development of new generating technologies over the next two decades may well hinge not only on the performance of these in nonutility applications but also on the evolving relationship between utilities, nonutility generators of power, and regulatory agencies.