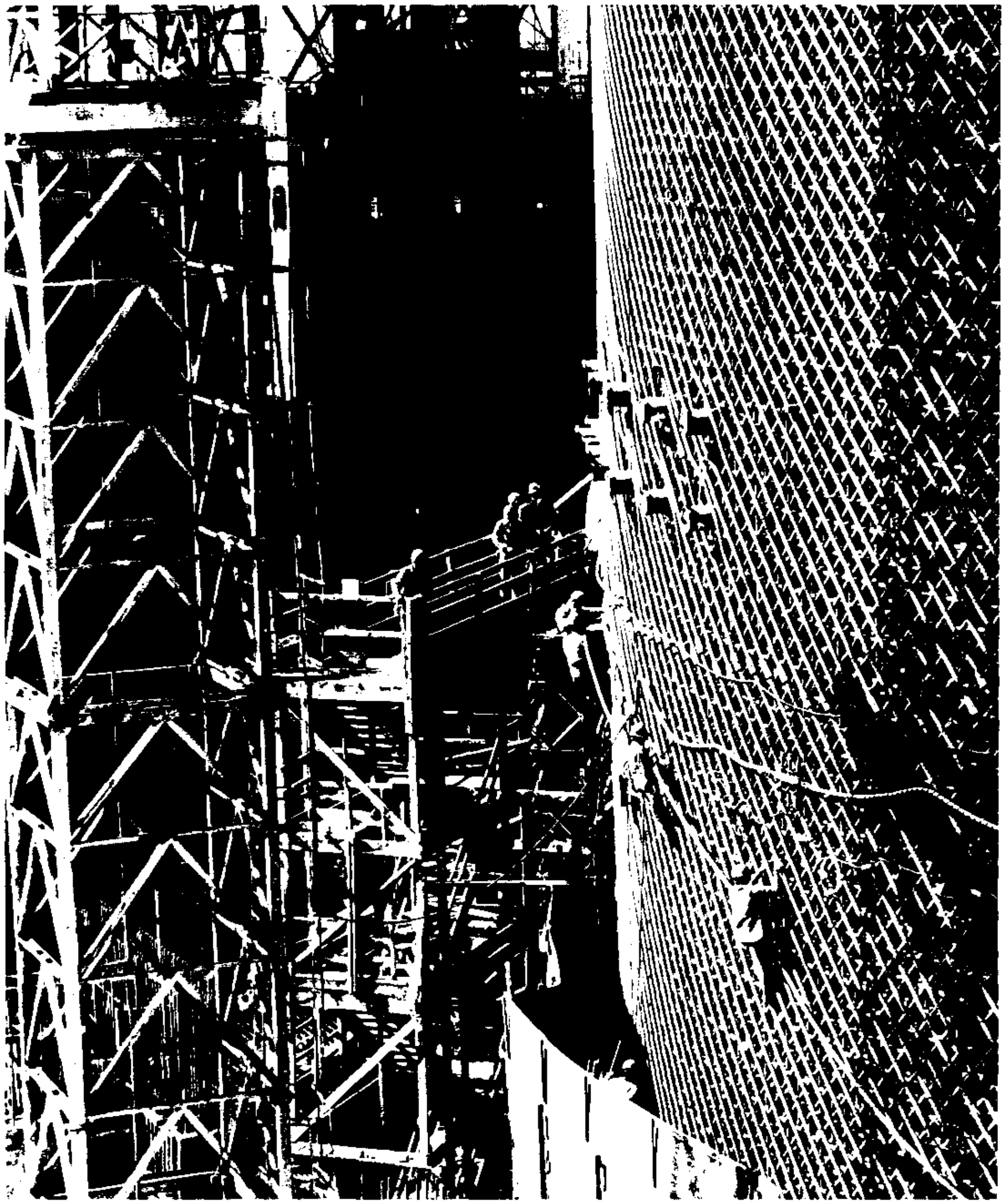
Chapter 3

The Uncertain Financial and Economic Future



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Contents

Tables

Figures

Chapter 3
The Uncertain Financial and Economic Future

If significant new electric-generating capacity is needed in the 1990's and beyond, and if nuclear power is to provide a major fraction of that capacity, utilities must order reactors some time before the end of the decade. Utility executives will compare the reliability, safety, and public acceptance of nuclear power (issues that are explored in other chapters in this report) relative to other types of generating capacity, especially to coal. But above all, they will treat the question of whether to order a nuclear plant as a strategic decision to be taken in the context of expected demand for electricity and the current and future financial status of the utility. Utility executives will compare the risks and returns from construction of more nuclear powerplants with the risks and returns of several other options for meeting their public obligation to provide adequate electric power.

This chapter will explore the elements of strategic choice for utilities that arise from the uncertainty of future rates of growth in electricity demand, the uncertainty of economic return on investment, and the uncertainty of construction and operating costs of nuclear powerplants. The chapter will also assess the regional and national implications of individual utility choices.

THE RECENT PAST: UTILITIES HAVE BUILT FAR LESS THAN THEY PLANNED

Utilities have built far less new electric-generating capacity in the 1970's and early 1980's than they expected to a decade ago. In 1972, the peak-year of generating capacity forecasts, utilities overestimated construction in the last half of the 1970's by 25 percent and overestimated construction in the first half of the 1980's by 60 percent (46). Utility predictions of future generating capacity declined over the decade but still greatly exceeded actual construction. The actual **generating capacity of 580 gigawatts** (GW) * in the summer of 1982 was about 75 GW lower than what had been forecast as recently as 1977 (70).

Both nuclear and coal plants were canceled in the late 1970's and early 1980's, but nuclear plants were canceled in far greater numbers and with far greater cost in sunk investments. Over 100 nuclear units were canceled from 1972 to 1983, more than twice the number of coal units (29,35). Almost $10 billion (1982 dollars) in investment costs was tied up in the 26 sites (some with 2 units) where at least $50 million per site had already been spent (35). Another 11 nuclear units totaling $2.5 billion to $3 billion in construction costs are expected to be canceled and another 5 units with $3 billion to $4 billion costs may be canceled (35,53).

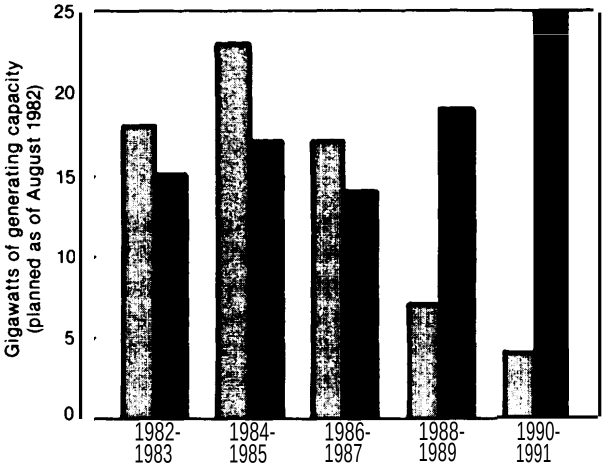
Of 246 GW of orders for nuclear plants ever placed, about 110 GW have been canceled. All of the 13 orders placed since 1975 have been canceled or deferred indefinitely and no new orders have been placed since 1978.

Utilities expect to complete many of the nuclear plants under construction but have not planned to build any more. Utilities still, however, are planning to build new coal plants. A total of about 43 GW of coal construction is planned for completion from 1988 to 1991 (see fig. 3) but only 11 GW of nuclear capacity is planned (much of which is likely to be canceled) (68).

One obvious reason for so many canceled and deferred plants is that from 1973 to 1982, electricity load grew at less than half the pace (2.6 percent per year) that it had grown from 1960 to 1972 **(7.1 percent per year). Most utilities in** the early 1970's used simple trend-line forecasts that took neither gross national product (GNP) or response to electricity price into account. They were unprepared for the change in electricity growth rates. Figure 4 shows a remarkable down-

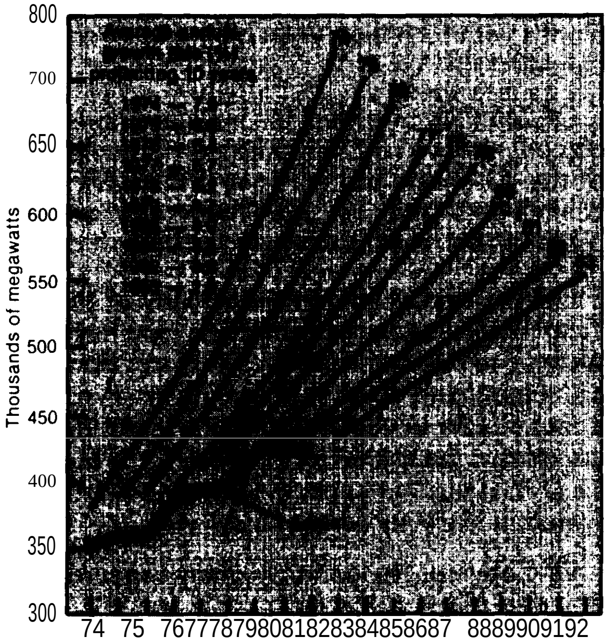
***One gigawatt equals 1,000 MW (1,000,000 kW) or slightly less than the capacity of the typical large nuclear powerplant of 1,100 to 1,300 MW. GW as used in this chapter always refers to GWe or gigawatts of electricity.**

Figure 3.– Planned Construction of Coal and Nuclear-Generating Capacity, 1982=91



SOURCE: North American Reliability Council, Electric *Power Supply* and *Demand 1982-1991,* August 1982.

Figure 4.—Comparison of Annual Ten-Year Forecasts of Summer Peak Demand (contiguous U.S.)



SOURCE: North American Electric Reliability Council, *Electric Power Supply and* Demand, 1981-1991, August 1982 and advanced release of the projections for 1983-1992 in April 1983.

ward trend in utility forecasts of future load growth. it is no surprise that utilities, making plans in the late 1960's and early 1970's, and unable to foresee the economic changes of the 1970's, planned to build more generating capacity than was eventually needed. Even with all the cancellations and deferrals, there was almost a 50-percent increase in electric-generating capacity from 1973 to 1982 while the average reserve margin* increased from about 21 percent in 1973 to about 33 percent (68,70). In between, the reserve margin peaked at about 37 percent as utilities completed and brought online plants that had begun construction before the slower load growth was recognized as the norm rather than as an anomaly (58).

In addition to the slowdown in electric load growth, powerplants also have been canceled and deferred due to the widely acknowledged deterioration in the financial condition of utilities. At the beginning of the *1970's,* utilities enjoyed good financial health. Almost 80 percent had bond ratings (Standard and Poors) of AA or AAA. Utility stock sold well above book value so that there was little difficulty financing new generating capacity from new issues of either debt or equity.

By 1981, however, utilities were in a greatly weakened financial condition. Currently, there are no electric utilities with AAA bond ratings and less than a fourth with AA ratings. At its low point in 1981, utility stock sold on average at only 70 percent of book value. This meant that any issue of new stock to pay for new generating plant would dilute the value of the existing stock (see box A later in this chapter). The financial deterioration was influenced in part by the general financial conditions of the decade, especially the rapid rates of inflation and the poor performance of the stock market. Beyond the influence of general economic conditions, however, the financial status of utilities deteriorated because of the enor-

*"Reserve margin" is defined as the percent excess of "planned resources" over "peak demand" where "planned resources" **includes installed generating capacity plus scheduled capacity purchases less sales.**

mous strain of financing requirements for new plants. Despite many cancellations and deferrals of powerplants, new plant financing increased from about $10 billion in 1970 to over $28 billion in 1982, of which more than two-thirds had to be financed externally (45).

The biggest incentive for utilities to cancel and postpone more nuclear than coal plants, was the more than fivefold increase in the constant dollar cost of nuclear plants from plants completed in 1971 to plants scheduled for completion in the 1980's compared to the approximately threefold increase in the constant dollar cost of coal plants (55,56). Another incentive to favor coal plants was their shorter leadtime, an average of 40 to 50 percent fewer months than for a nuclear plant (l).

Looking ahead, the prospects for substantial numbers of new central station powerplants appear fairly uncertain. The prospects for more nuclear plants appear even more uncertain. The reasons why this is so are laid out in the rest of the chapter. The next section describes the uncertainty about the future growth rates in electricity demand. With some assumptions about the future it is reasonable to expect that the fairly slow growth rates (1 or 2 percent per year) of the past few years will continue. With equally plausible assumptions, however, electricity load growth could resume at rates of 3 to 4 percent per year. The sources of uncertainty are described in the next section.

The third section explains why utilities can afford to wait awhile before ordering powerplants in large numbers, since reserve margins are now so high. Sooner or later, however, as this section points out, some number of new powerplants will need to be built to replace aging powerplants and meet even modest increases in electric load.

The fourth section of the chapter presents an argument that there may be systematic biases in rate regulation that discourage those types of generating capacity that are of high capital cost and high risk relative to other types. Over the long run such rate regulation would discourage further construction of large coal and nuclear plants even when increased load and replacement of existing plants would make it sensible to construct central station plants, for which capital costs are high relative to fuel cost.

The fifth section of the chapter lays out the uncertainties involved in constructing and operating a nuclear plant which discourage utilities from ordering more nuclear plants even when they decide to order more central station powerplants. Construction costs have risen much faster than general price increases and vary severalfold from plant to plant even when built the same year. In addition, there is a financial risk of at least several billion dollars from an accident that disables a powerplant and more from one that causes damage to public health and property. To date insurance is available to cover only a fraction of this risk.

Given the uncertainties of demand and nuclear construction cost, utility decisions to cancel nuclear powerplants and some coal plants have been sensible, and in the short-term interests of the ratepayers. Over the long run, however, if ratemaking discourages electric-generating technologies of greater capital cost and greater risk, further investment in nuclear powerplants could be discouraged even if it were in the longer term interests of ratepayers.

The final section of the chapter describes the choices utilities have and the choices they seem to be making. Under a few specific assumptions about changes in outside circumstances and rate regulation incentives, utilities could order nuclear plants again. It appears now, however, that they will avoid central station construction as long as possible and then build coal plants.

THE UNCERTAIN OUTLOOK FOR ELECTRICITY DEMAND

From 1973 to 1982, annual increases in electricity demand averaged 2.6 percent. If these growth rates were to continue for the next 20 years, they would provide no more than a weak stimulus to further building of central station powerplants, including nuclear powerplants. (See the detailed discussion of capacity requirements in the next section.) It would be possible for most utilities, with some effort, to avoid building central station powerplants altogether until the late 1990's by encouraging conservation, load management, cogeneration, and small sources of power from hydro and wind; or by purchasing from U.S. utilities with excess capacity or from Canadian utilities; or by keeping existing plants online past normal retirement age. These strategies are discussed later in the chapter.

What are the chances that the average electricity demand growth rate will be significantly higher or lower than 2.6 percent per year? A significantly lower growth rate would make it difficult to justify any major construction of central station powerplants. A significantly higher growth rate would make a strategy of little or no powerplant construction difficult to sustain.

Published projections of electricity demand reflect considerable uncertainty about future growth rates. As is clear from figure 4 above, the utilities' own estimates of future peak demand have dropped each year since 1974 and now average an annual increase of 2.9 percent from 1983 to 1992 (70). Some studies (e.g., the Energy Information Agency and Starr and Searl of EPRI) project higher rates of electricity growth than the electric utilities do, although none project more than 4 percent annual growth through 1990 (27, 51 ,83). Only one (Edison Electric Institute) projects more than 5 percent from 1990 to 2000. Several studies (e.g., Audubon and the Solar Energy Research Institute) on the other hand, project very low rates of annual electricity growth of O to 1.5 percent (77,84).

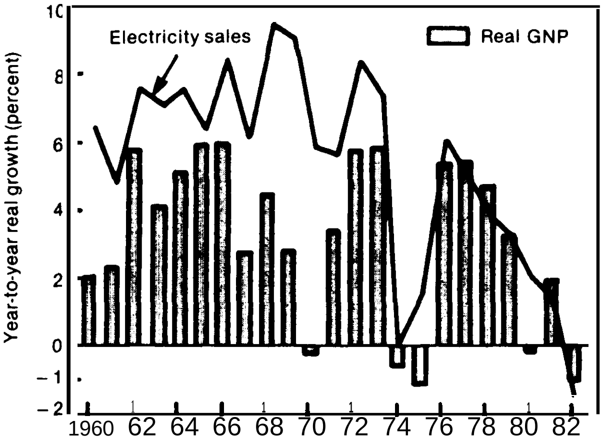
One of the reasons for this range is different assumptions about the future growth rates in GNP. The projections of faster electricity growth assume a range of 2.5 to 3.0 percent annual GNP growth per year (51). The projections of slower electricity growth assume somewhat slower growth rate in real GNP, a range of 2.0 to 2.8 percent per year (77). In general, however, all these projections assume that the United States has a "mature" economy and increases in real GNP faster than an average of 3.0 percent per year are not likely.

The projections disagree more significantly about the likely future relationship between growth rates in GNP and growth rates in electricity demand. Projections of faster electricity growth assume that electricity will increase faster than GNP. Projections of slower electricity growth asume that electricity demand will increase significantly less fast than GNP.

The ratio between electricity growth rates and GNP growth rates has indeed dropped since the 1960's. As is shown in figure 5, electricity growth rates were about double GNP growth rates in the 1960's and approximately equal to GNP growth rates (except for recession years) in the 1970's. Those expecting fast growth rates in electricity regard the late 1970's as an anomaly and expect a resurgence of a ratio of electricity to GNP growth of more than 1.0. Those expecting slow growth rates in electricity assume that the ratio of electricity growth to GNP growth will fall still further, well below 1.0. They expect that electricity will continue to behave like other forms of energy for which ratios to GNP have dropped steadily since *1973.*

The sources of uncertainty in electricity demand forecasts are very evident from a look at

Figure 5.—A Comparison of the Growth Rates of Real GNP and Electricity Sales, 1980=82



SOURCE: Craig R. Johnson, "Why Electric Power Growth Will Not Resume, " *Public Utilities Fortnigfhtly,* Apr. 14, 1983 from data in the EIA, Annual Report to Congress 1982 and the Edison Electric Institute, the uncertainty surrounding the factors underlying the forecasts. The uncertainty exists both in conventional macroeconomic approaches to forecasting which relate electricity growth to expected changes in GNP, electricity prices and the prices of competing fuels. (This is sometimes referred to as the top-down approach.) There is comparable uncertainty about the factors underlying engineering or end-use projections of electricity use. This approach (sometimes called bottom-up analysis) identifies possible technical changes in the use of electricity that are economically feasible—such as improvements in appliance and electric motor efficiency, opportunities for **fuel switching, and new electricity-using industrial technologies–and then estimates the likely market penetration of these changes.**

The Top-Down Perspective on Electricity Demand—Sources of Uncertainty

One of the advantages of top-down analysis of electricity demand is that uncertainty is confined to only a few powerful variables—future growth in GNP, changes in electricity prices, and changes in the prices of competing fuels and the responsiveness of electricity demand to each.

The Influence of Economic Growth. -Future growth of GNP is a major source of uncertainty, both because income and industrial production are assumed by economists to have major impacts on electricity demand, and because of some deep uncertainties about the future direction of the economy. Even the fairly narrow range of GNP growth rates of 2 to 3 percent that has been assumed by the major electricity demand projections implies a range of electricity demand growth rates (assuming *no* price influence) of about 2 to 3 percent over the long run if electricity demand follows the income response patterns identified in the past (79). Many observers concede the range is even wider, Those with private misgivings about the future health of the economy accept the possibility of an annual rate of GNP growth lower than 2 percent. Optimists about economic renewal and increased productivity suggest the potential for a higher rate of growth.

Regional uncertainties about economic growth are more extreme than national ones. Income and industrial output have fallen in some regions as a result of the recent recession and the extent of long-term recovery from the recession in these regions is unclear. Rapid population growth is expected to occur in the South and Southwest.

Electricity Prices.– Future electricity prices and their impacts are a second source of uncertainty about electricity demand growth. This is both because there is disagreement about future change in electricity prices and because there is uncertainty about how electricity demand responds to electricity prices.

From 1970 to 1982, average electricity prices increased in constant dollars at about 4 percent per year, reversing a 20-year trend of decreasing real prices (26). There is considerable disagreement about the future course of electricity prices even though they should be easier to project than oil or gas prices because they are largely determined by regulatory rules that are predictable. The Energy Information Administration in the Department of Energy (DOE) has consistently projected very slow increases in real electricity prices of less than 0.5 percent per year until 1985 and 1.4 percent per year after that (27). The Office of Policy Planning and Analysis, also of DOE, projected somewhat more rapidly increasing electricity prices, at 2.4 percent per year until 1995 with level prices after that (20). Finally, Data Resources Inc. (DRI) has projected sharply increasing electricity prices for both industrial and residential users of 3.7 percent per year until the mid-1 980's, slower increases until 1990 and less than 0.5 percent per year from 1990 to 2000 (18).

Forecasts of electricity prices disagree principally about the future cost of coal for electricity, the future construction cost of nuclear and coal powerplants and the future rate regulation policies of Public Utility Commissions. Stabilizing of electricity prices in the 1990's is expected to occur because of a growing share of partially depreciated plants in the rate base and little new *con*struction. (See the discussion of these factors in later sections of this chapter.)

Response of Electricity Demand to Electricity **Prices.—There is generally less agreement about the impact of electricity prices on electricity demand than there is about the impact of changes in GNP. Most analysts agree that the short-run response of electricity demand to an increase in electricity prices is very limited—l O to 20 percent of the price increase. Based on comparisons from State to State, however, analysts estimate the long-run response to be much greater–50 to 100 percent of the price increase. (The response to a price increase is always a decrease in demand.)** For example, an increase of 2 percent in electricity prices would be expected to result in a short-run decrease in electricity demand of 0.2 to 0.4 percent (from what it would have been otherwise), but a long-run decrease in electricity demand of 1 to 2 percent.

Prices of Competing Fuels.–Very few analysts have attempted to estimate the long-run response of electricity demand to changes in the prices of other (and competing) forms of energy of which the principal competitor is natural gas. Of these attempts, the consensus is that electricity demand would be expected to increase (over the long run) about 0.2 percent for every 1 percent increase in natural gas prices.

The Energy Information Administration projects that natural gas prices will increase at more than 10 percent a year (in constant dollars) until 1985 and more slowly, at 5 percent per year after that until 1990 (27). DRI, on the other hand, projects somewhat slower increases of about 3 percent per year through the 1980's and *1990's (18).*

In some areas, especially New England, oil is the chief competitor to electricity and the chief source of uncertainty. Oil prices are now higher than natural gas prices and are projected to increase but more slowly than natural gas prices.

The Impact of Prices on Demand .–The combined effect of uncertainty about future electricity and natural gas (and oil) prices and uncertainty about how electricity demand responds to changes in electricity prices is enough to explain a range of uncertainty in electricity demand from very slow growth to quite rapid growth. This is illustrated in table 3. If GNP is projected to grow at 2.5 percent (the midpoint of the range assumed in current forecasts) and the long-run response to increases in income is assumed to be 100 percent, the effect of price and price response assumptions is to produce a projection of 1.1 percent annual increase in electricity demand, at the low end, and of 4 percent at the high end. It would be possible, for example, for electricity demand to grow at 4 percent per year, if electricity prices increase at no more than 1 percent per year (in constant dollars) while natural gas prices increase at 10 percent per year, and there is a relatively small long-run decrease in demand in response to an electricity price increase (defined as a long-run elasticity of – 0.5).

Timing of Response to Prices.–Unfortunately no analyses have been published of the long-run

Table 3.—Growth Rates in Electricity Demand Given Different Price Responses[a]

Rates of electricity and gas price increase	Annual increase in electricity demand given: Low long-run price response	High long-run price response
1. High electricity prices (2%/yr) Moderate gas prices (3%/yr)	2.1%/yr	1.1%/yr
2. Low electricity prices (1'\O/yr) Moderate gas prices (3%/yr)	2.6%/yr	2.1%/yr
3. Low electricity prices (1%/yr) High gas prices (5%/yr).	3.0%/yr	2.5%/yr
4. Very high gas prices (10%/yr) Low electricity prices (1%/yr).	4.0%/yr	3.5%/yr

[a]Also called price elasticities. *See Assumptions.*

Assumptions: GNP increases at 2.5 percent par year; Income elasticity of electricity demand - 1.0; response of electricity demand to gas price (cross-elasticity) - 0.2; response of electricity demand to electricity price (own-elasticity): a) low = 0.5, b) high = –1.0.

SOURCE: Off Ice of Technology Assessment based on a presentation by James Sweeney to an OTA workshop.

response of electricity demand to electricity prices in the crucial decade since the 1973 oil embargo. The estimates mentioned above were all based on data up to 1972. The chief reason is because this analysis cannot be done without consideration of the timing of the long-run response. Not only have electricity prices (in constant dollars) changed from decreasing to increasing, but competing fuel prices (which also affect electricity demand) changed from decreasing to increasing even more dramatically.

The length of time it takes for the long-run price response to be felt is crucial to making any estimate of this response. If the "long run" is 3 to 4 years, we have already seen much of the response to the price increases of the 1970's. If the "long run" is 10 years or longer, we are just now beginning to witness the effects of actions taken in response to those price increases.

This lack of understanding of how long it takes for the full long-term response to increases in electricity prices makes it difficult to predict what still remains of consumer and industrial responses to the increasing electricity prices of the last decade. If the response takes 10 years or longer, the effects will last until the early 1990's.

Electricity Rate Structure.-The uncertainty of price impacts is further complicated because forecasts of average electricity price do not fully capture the potential price changes that will influence electricity demand. Decisions of industry and consumers are also influenced by the price of an additional unit of electricity, that is the *marginal price* of electricity. Utilities have recently begun to shift from "declining block rate" structures (in which each additional block of units of electricity costs less than previous blocks) to increasing block rate structures (in which each additional block costs more than previous blocks). There is no current survey of data on utility rate structures, but a crude estimate can be made that as many as one-fifth of all utilities may have increasing block rates for households. The number of such utilities is likely to continue to grow.

Regional Differences in Demand Response to Price Increases for Individual Utilities. -Another source of uncertainty is that individual utilities will have very different experience in electricity prices from the national average. A recent regional analysis of projected changes in electricity prices shows a mixture of declining electricity prices in some regions and increasing electricity prices in others **(48).** Real electricity prices in the Mountain region are forecast to drop by an average of more than 3 percent per year (in constant dollars) until 1987 and then stay nearly stable until 2000. Meanwhile, in the West South Central region electricity prices are projected to increase by an average of 4.6 percent per year until 1991 and then taper off slowly until the year 2000. Price changes as different as these will inevitably induce a wide regional variation in demand growth rates. Declining rates in the Mountain region should eventually stimulate increases in electricity demand while the opposite occurs in the West South Central region. This regional variation in both present and projected electricity prices will complicate and perhaps delay industry's investments to improve efficiency.

The Bottom-Up Perspective on Electricity Demand—Sources of Uncertainty

Within an overall framework of economic growth rates and changes in relative energy prices, bottom-up or end-use analysis offers a closer look at how electricity customers might actually change their patterns of electricity use in response to prices and income changes. Industrial customers purchase the most electricity, about 38 percent of the approximately 2.1 billion kwh sold in 1981. * Residential customers are close behind with **34** percent of all sales in 1981. Commercial customers and other customers purchased **24** and 4 percent, respectively.

Given a range of plausible assumptions about how customers are likely to change their patterns of electricity use over the next two decades, growth rates in electricity demand that range from 1 percent per year to as high as 4 percent per year are possible.

From a close look at each sector it is clear that a few variables are far more important than

*** 1981 data are used because industrial purchases had fallen to 35 percent of the total in 1982 as a result of the economic recession.**

others. Industrial electricity sales will be strongly influenced by the output experience of several key industries such as steel and aluminum, by the market penetration of greater efficiency in the use of electric motors, and by the success of several important new electrotechnologies for replacing oil and natural gas sources of industrial process heat.

The future rate of household formation will also strongly influence residential sales. How fast the use of electric heat and central air-conditioning spreads into new and existing housing units is also important, as is the success of high-efficiency appliances, air-conditioners, and heat pumps.

For future commercial sales of electricity the important future influences will be: the rate of construction of new commercial buildings; the prospects for significantly more efficient air-conditioning and lighting; and the potential for significant increase in electricity used for computers and other automation.

Utilities, in fact, are beginning to monitor such variables more closely in the effort to reduce some of the uncertainty about future growth rates in electricity. Utilities are increasingly turning to end-use modeling of future demand. This is in part because such models can be used to assess the impact of utility conservation and load management programs, but it is also possible to monitor important indicators of future customer behavior. Some utilities and State governments are indeed undertaking load management and conservation programs in order to directly influence customer behavior and reduce future uncertainty.

There is general acceptance that the high and low end of the bottom-up range is influenced by the key variables of price and income (GNP) used in top-down analysis. Slow increase in electricity prices is a weak stimulus to improvements in the efficiency of electricity use even if they are technically feasible, while rapid electricity price increases are a strong stimulus to efficiency improvements. Similarly, rapid increases in natural gas prices relative to electricity prices will stimulate the adoption of new electrotechnologies that substitute for natural gas. Less rapid price increases will provide less stimulus.

Industrial Demand for Electricity .-The electric-intensity of U.S. industry (electricity used per unit of output) has held steady since 1974. This is despite a steady decrease for more than two decades in the overall use of energy per unit of industrial output. The steady relationship of electricity to industrial output is the product of two opposing trends: a steady increase in electricity-use in industries which are heavy users of electricity, and a steady **decrease in the proportion of output from those same industries relative to total U.S. industrial output (58). Looking ahead, there is considerable uncertainty about both these trends.**

Electricity use in industry is concentrated. Just 13 specific industrial sectors* consume half of all industrial electricity. These are: primary aluminum, blast furnaces, industrial inorganic and organic chemicals not elsewhere classified, petroleum refining, papermills, miscellaneous plastic products, industrial gases, plastics materials and resins, paperboard mills, motor vehicle parts, alkalis and chlorine, and hydraulic cement.

Future rates of output growth in several of these industries are highly uncertain. For example, the industrial output of primary metals, which includes both aluminum and steel, decreased by about 1.0 percent per year between 1972-74 and 1978-80 (57). Capacity expansion plans for both steel and aluminum are down about two-thirds from their level a decade ago (50).

Within the chemicals industry, electricity is used heavily in the production of several basic chemicals such as oxygen (where it is used for refrigeration), and chlorine (where it is used for electrochemical separation). Although the chemicals industry as a whole grew by an average of 4.5 percent per year from 1974 to 1980, the production of these basic electrically produced chemicals grew only 1 to 2 percent per year (oxygen and chlorine) or actually decreased (acetylene and phosphorus) (1 1). Observers of the chemical industry expect this trend to continue as demand for basic chemicals becomes saturated and some production moves overseas. The U.S.

***As identified by four-digit Standard Industrial Classification (SIC) codes.**

chemical industry is expected to concentrate increasingly on small volume specialty chemicals, which use relatively little electricity for production.

Since chemicals, iron and steel and primary aluminum alone account for more than a third of electricity use in industry, a 2 percent lag in growth of these electricity-using industries behind general industrial output would alone cause a lag of about **0.5 percent in electricity demand behind** overall growth in industrial output.

In addition to being concentrated by type of industry, electricity use in industry is also concentrated by function. Uncertainty about the direction of trends in electricity use in electric-intensive industries comes about because electricity use will probably become more efficient in two of the functions (electric motors and electrolysis) and is likely to expand into significant new uses in the third function (electricity to supply or substitute for process heat).

About half of all electricity use in industry is used for electric motors, including compressors, fans and blowers, and pumps (3). Improvements in the efficiency of electric motors are likely to be continuous for 10 to 15 years through improvements in the motors themselves and through improved efficiency of use which takes advantage of new semiconductor and control technology. Thus, electricity use per unit of output for these purposes could decrease by 5 percent (if there is little price stimulus) or up to 20 percent (if there is significant price stimulus). Some of this improved efficiency should come about as a result of past price increases, as capital stock turns over. impetus for the rest will depend on future electricity price increases, and the cost of installing the control technologies.

Another 15 to 20 percent of all industrial electricity is used for electrolysis of aluminum and chlorine (3,81). Aluminum electrolysis is more likely to decrease than increase as a fraction of industrial use, because efficiency improvements of 20 to 30 percent are technically possible from several technologies and are probably necessary (given sharply increasing prices for electricity in the Northwest, Texas, and Louisiana where plants have been located) to keep aluminum production in the United States competitive with aluminum production overseas (81).

Electric process heating in industry accounts for only about 10 percent of current uses of electricity but has great potential to become much more important as new electric process heating techniques are developed that make better **use of** electricity's precision and ability to produce very high temperatures. In some important high temperature industries such as cement, iron and steel, and glassmaking, electricity makes up 20 to 35 percent of all energy use and could as much as double its share.

Some techniques being developed could have very large impacts on electricity demand. These include plasma reduction and melting processes for primary metals production, and induction heating for shaping and forging. Other techniques such as lasers and robotics, however, are likely to have small impacts on electricity demand because only small amounts of electricity are used for each application. The biggest lasers, for example use only about 1 to 2 kW. Most use under 100 W. Table 4 shows an assessment of the relative impact likely from each of the newer techniques (81).

Great uncertainty surrounds the contribution to industrial electricity demand from the most important new electrotechnologies. The iron and steel industry could experience the greatest increase in electricity demand. Production and profit levels, however, in that industry are uncertain. Overall growth in the steel industry is projected to be only about 1.5 percent per year to 2000 (81). The contribution of electric arc steelmaking from scrap iron is expected to increase from approximately one-fourth to at least one-third of the total, but the potential for plasma reduction and melting is more uncertain partly because there may be too little capital to take advantage of technological advances (81). If new technologies penetrate slowly, the impact on electricity demand could be minimal until the late 1990's. It is conceivable, however, that rapid penetration could occur with a few very successful new techniques which in turn may increase the U.S. steel industry's competitive position and prospects for growth. In such circumstances,

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Table 4.—Estimated Impact of Industrial Electrotechnologies in the Year 2000

	Rough estimates of GW of capacity				
	1983	2000	Change to 2010[a]	Load factor	Level of uncertainty
Arc furnace steelmaking.	3.5-4.5	5-7	+	High	Low
Plasma metals reduction	0	2-4	+	High	High
3. Plasma chemicals production . . .	0	3-5	+	High	High
4. High-temperature electrolysis (aluminum and magnesium)	8-9	9-12	O or –	High	Low
5. Induction melting (casting)	3-4	4-5	o	Low and off peak	Moderate
6. Plasma melting	0.05	?[b]	+	High	Very high
7. Induction heating (forging)	5-7	8-10	o	Moderate	Moderate
8. Electro slag remelting.	0.075	0.15	+	Moderate	Moderate
9. Laser materials processing	0.0005-0.001	0.001-0.002	+	Moderate	Moderate
10. Electron-beam heating	0.006-0.008	0.015-0.02	+	Moderate	Moderate
11. Resistance heating and melting	0.3-0.5	0.4-0.6	O or –	High	Low
12. Heat pumps	0.1	1-3	+	High	Moderate
13. Electrochemical synthesis, electrolytic separation, chlorine/caustic soda	4-5	4-5	o	High	Low
14. Microwave and radiofrequency heating	0.5	7	+	Moderate	High
15. Ultraviolet/electron-beam coating	0.01-0.02	0.5-1	+	Moderate	Moderate
16. Infrared drying and curing	0.4-0.5	0.5-1	o	Moderate	Low
17. Electrically assisted machining and forming.	<0.001	<0.001	—	—	—
18. Low-temperature plasma processing	<0.001	<0.001	—	—	—
19. Laser chemical processing	0	<.5GW[c]	—	—	—
20. Robotics	<0.001	<0.001	—	—	

[a]Explanation: " + " = Increase to 2010; "0" = stable to 2010; " – " = decrease to 2010.
[b]Any capacity in plasma melting directly competes with electric arc furnace steelmaking.
[c]This will probably only be used in U.S. Government-owned facilities for Uranium isotope Separation.

SOURCE: Table prepared by Philip Schmidt, based on research for a report publicized by EPRI in early 19S4, *Electricity and Industrial Productivity: A Technical and Economic Perspective* (81).

there could be a substantial impact on electricity demand by the early 1990's.

The role of cogeneration* in satisfying future industrial electricity demand is a final source of uncertainty. (Cogeneration is discussed further in the section on utility strategies and was a subject of a recent OTA report *Industrial and Commercial Cogeneration (72).)* A recent study by DOE estimated that cost-effective opportunities existed in industry for about 20 GW of self-contained cogeneration without sales to the outside electrical grid, a potential increase of slightly more than the current installed capacity of about 14 GW with about 3 GW additional capacity in the planning stage (72). if fully realized, an increase in cogeneration of this magnitude would reduce the growth rate of purchased electricity by about 0.5 percent per year. Cogeneration is being adapted more slowly than the market potential indicated earlier partly because the success of industrial energy conservation programs has reduced industrial requirements for steam.

For the 1980's, the highest growth rate in industrial electricity demand is likely to be no more than equal to industrial output, and growth rates could fall as low as 2 percentage points below industrial output growth. For the 1990's, it is quite possible that electricity demand could grow faster than industrial output (20). The reasons for possible faster growth in industrial electricity demand in the 1990's than in the 1980's should be clear from the above discussion. The output of such electricity-using industries as steel and aluminum

*The combined production of electricity and useful steam (or hot water) in one process.

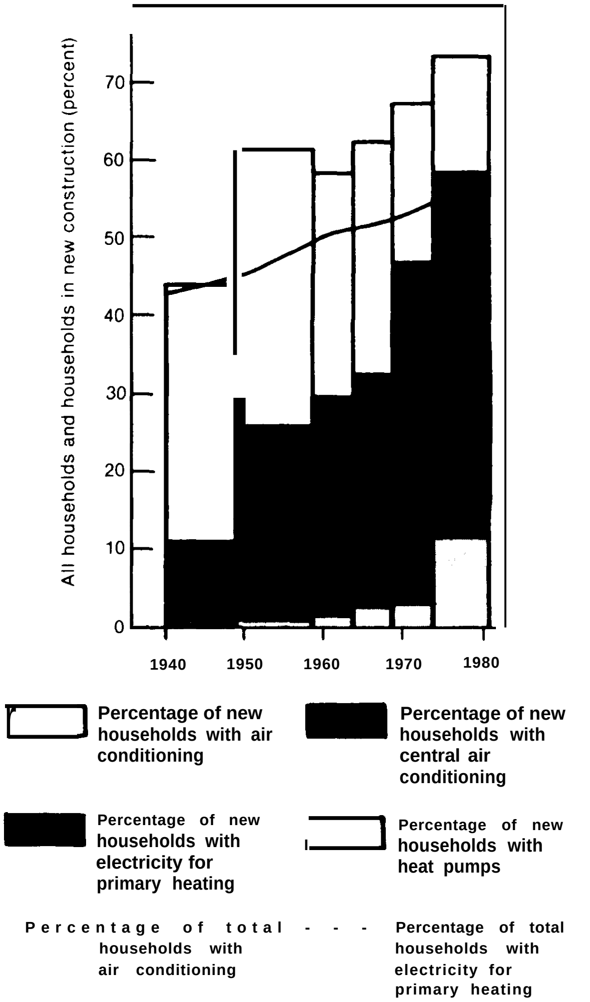
is likely to continue to grow very slowly during the 1980's, but may grow more rapidly in the 1990's. Technologies for improving the efficiency of use of electric motors are also likely to have the greatest impact in the 1980's, while new electrotechnologies for substituting electricity for process heat are not likely to have a big impact in the **1980's because they are now a small share of total electricity use. Even** if they grow rapidly, they cannot have a major impact on overall industrial electricity demand until they are a larger fraction of the whole, sometime in the 1990's.

Residential Demand for Electricity .-From a bottom-up perspective, what happens to future electricity demand from households depends both on how fast the total number of households increases and on what happens to electricity use per household.

There is uncertainty, first of all, about the rate of household formation. Over the decade from 1970 to 1980, the U.S. population formed households at a rate much faster than population growth. In current census projections, this trend is expected to continue through the 1980's, **resulting in a fairly rapid rate of household formation of 2.2 percent per year and a further drop in household size from about 3.2 people per household in 1970 to 2.8 people** in 1980 to 2.5 people per household in 1990. On the other hand, were the U.S. taste for living in smaller and smaller households to become less important, the growth rate in household formation could fall to 1 percent per year or less.

The potential for increased use of electricity per household largely comes about because the number of households with air-conditioning and electric heating is still increasing. This is shown in figure 6. As of 1979 only 16 percent of all households had electric heat, but about half of new dwelling units were heated electrically. As new dwelling units replace existing ones, the percent of total dwelling units with electric heat could double or triple. A doubling of the share of all households heated electrically (assuming no increase in the efficiency of space heat) would add about 0.7 percent per year to household growth in electricity demand. The potential for increased use of electric space heating, however, will be influenced by the relative cost of electric heat

Figure 6.—Penetration of Air-Conditioning and Electric Heating in Residential Sector



SOURCE: **Department of Energy,** *The future of Electric Power in America. Economic Supply for Economic Growth,* **Report of the Electricity Policy Project, June 1983, This graph was prepared from data in the EIA residential energy consumption surveys**

which will in turn be reduced by increases in electric heating efficiency. About 70 percent of new households have air-conditioning compared to about 55 percent of existing households, so modest increases in electricity use from air-conditioning are also likely.

The use of electricity to heat water may expand beyond the 30 percent of households that now use it and could as much as double if there is a big decrease in the relative cost of electric and gas-heated hot water. The demand for other electric appliances is considered largely saturated and unlikely to expand substantially beyond the demand caused by increases in new households. Most (98 percent) of all households have refrigerators, 45 percent have freezers, and sO percent have electric ranges (10).

What makes projecting household electricity use highly uncertain is the difficulty of knowing how much electricity use per household will be reduced because of increases in appliance and lighting efficiency. From a comparison of the most energy-efficient appliances and lighting available in 1982 with the more typical appliances and lighting available (table s), it is clear that efficiency increases of more than **so percent can be achieved for all types of appliances, except freezers for which efficiency improvements since 1973 have already increased almost 50 percent (42). Some of these highly efficient appliances cost up to 100 percent** more than the typical appliance, but the extra cost would normally be paid back in electricity savings in **4 to 8 years.**

Continued increases in electricity prices will increase the demand for these high-efficiency products. Since some regions will have much larger electricity price increases than others, these may well create a large enough market to bring the prices of the high-efficiency products down. In some regions, market incentives will be augmented by local utility programs: rebates to purchasers of energy-efficient appliances (e.g., Gulf Power Co. in Florida) or rebates and bonuses to dealers who sell them (e.g., Georgia Power Co.) (42). Most observers agree that some improvement in appliance efficiency will occur. With modest increases in electricity prices, refrigerators are expected to reduce their average per unit electricity use by 10 percent. With stronger price incentives and perhaps utility market inducements electricity for refrigerator use may decrease by so percent both because of greater efficiency and smaller volume refrigerated. There is a similar range of possibilities for other appliances.

Commercial Demand for Electricity .-The commercial sector is the smallest of the three but is growing the fastest in electricity use. Sales of electricity to the commercial sector increased 3.9 percent per year over the decade from 1972 to 1982, faster than sales to either the industrial or residential sector, although less than half the rate of increase in commercial-sector sales of the previous decade **(26).**

One of the reasons for uncertainty in projecting future commercial demand for electricity is that there is no reliable source of data on how fast the commercial building stock is increasing. From the one available source (a 1979 survey of nonresidential building energy consumption (33)), it appears from the number of recently built buildings that commercial building square footage increased by about 2.7 percent per year from 1974 to 1979, somewhat slower than GNP growth of 3.8 percent per year over the same period. Over the same period, electricity sales increased about 4.2 percent per year, a rate faster than GNP and much faster than the increase in building square footage. If the same trends con-

Table 5.-Efficiency Improvement Potential From Typical to Best 1982 Model: Household Appliances

	Typical 1982 model	Most efficient 1982 model	Percent increase in efficiency
Heat pump: C. O.P.[a]	1.7	2.6	+ 53
Electric hot water heater: C. O.P.[a]	0.78	2.2	+ 182
Room air-conditioner: EER[b]	7.0	11.0	+ 57
Central air-conditioner: SEER[c]	7.6	14.0	+84
No-frost refrigerator-freezer: energy factor[d]	5.6	8.7	+55
Chest freezer: energy factor[d]	10.8	13.5	+25
Bulb producing 1,700 lumens: efficacy (lumens/watt)[e]	17	40	+ 135

[a]C.O.P. is the coefficient of performance, kWh of thermal output divided by kWh of electrical input.
[b]EER is the energy efficient ratio obtained by dividing Btu/hr of cooling Power by watts Of electrical power input.
[c]SEER is a seasonal energy-efficient ratio standardized in a DOE test procedure.
[d]Energy factor is the corrected volume divided by daily electricity consumption, where corrected volume is the refrigerated space plus 1.63 times the freezer space for refrigerator/freezers and 1.73 times the freezer space for freezers.
[e]1,700 lumens is the output of a 100-watt incandescent bulb.

SOURCE: Derived from Howard S. Geller, *Efficient Residential Appliances " Overview of Performance and Policy Issues,* American Council for an Energy Efficient Economy, July 1983.

tinue, and commercial square footage continues to grow more slowly than GNP, commercial electricity use will only increase as fast or faster than GNP as long as electricity use per square foot continues to increase.

Electricity use per square foot in commercial buildings may continue to increase for several reasons. Only **24 percent of existing commercial building square footage but almost half (48** percent) of the new building square footage is electrically heated (33). If these trends continue the share of buildings that are electrically heated could double.

Air-conditioning in commercial buildings is probably saturated. About 80 percent of all buildings have some air-conditioning. Small increases in electricity use per square foot can come about by air-conditioning more of the building and by replacing window air-conditioners with central or package air-conditioners. Window air-conditioners cool 20 percent of the existing building stock, but only 9 percent of the newest buildings (33).

Greater use of office machines and automation might increase electricity use both to power the machines and to cool them in office buildings, stores, hospitals, and schools. Machines, however, are less likely in churches, hotels, and other categories of commercial buildings.

The potential for increased efficiency of electricity use in commercial buildings is less well known than for residential buildings because commercial buildings are very diverse and the potential for increased efficiency depends partly on success in balancing and integrating the various energy loads: lighting, cooling, heating, refrigeration, and machines. OTA analyzed the theoretical potential for reductions in electricity and fuel use in commercial buildings in a recent report, Energy Efficiency *of Buildings in* **Cities (71),** and found that electricity use for lighting and air-conditioning in commercial buildings can be reduced by a third to a half. Heating requirements also can be reduced substantially by recycling heat generated by lighting, people, and office machines from the building core to the periphery. There is still very little verified documentation of energy savings in commercial buildings, however, and therefore, considerable uncertainty remains about the potential.

The results of the bottom-up analysis for the commercial sector indicate a demand for electricity that will increase for a few years at about the rate of increase of GNP but with wide ranges of uncertainty. It could be higher as a result of faster penetration of electric space heating and more air-conditioning and big loads from office machines, or lower as a result of big improvements in the efficiency of commercial building electricity use. By the 1990's, however, when the demand for electric heat in commercial buildings will be largely saturated, the trend rate of growth in electricity demand is likely to settle to the growth in commercial square footage, somewhat less than the growth rate of GNP.

Conclusion

Utility executives contemplating the construction of long leadtime powerplants must contend with considerable uncertainty about the probable future growth rates in electricity demand, The range of possible growth rates encompasses low average growth rates of 1 or 2 percent per year, which would justify very few new large powerplants, up to fairly high growth rates of 3.5 to 4 percent per year, for which the pressure to build several hundred gigawatts of new large powerplants is great, as will be clear from the discussion in the next section.

The sources of uncertainty are many. Future trends in electricity prices are viewed differently by different forecasters, because there is disagreement about future capital costs of generating capacity, future rates of return to capital and future prices of coal and natural gas for electricity. There also is uncertainty about how consumers and industry will respond to higher prices, given many technical opportunities for improved efficiency in appliance use and industrial electricity use and increasing numbers of promising new electrotechnologies that could substitute for the use of oil and natural gas for industrial process heat. Several of the industries, such as iron and steel, however, where the new electrotechnologies could have the greatest impact, face an uncertain future.

At present, utility strategy for supplying adequate electricity is influenced heavily both by the recognition of uncertainty about future growth in electricity demand and by recent financial difficulties and regulatory disincentives for large capital projects. The influence of utility rate regulation and current utility strategies are discussed later in the chapter.

RESERVE MARGINS, RETIREMENTS, AND THE NEED FOR NEW PLANTS

Powerplants are planned and ordered many years in advance of when they are needed. in order to produce power for sale by 2000, nuclear powerplants on a typical schedule would have to be ordered by 1988, **or 1990 at the latest, and coal plants or nuclear plants on an accelerated schedule, must be ordered by 1992 or 1993. Sources of generating capacity with** shorter lead-times, such as gas turbines or coal conversion, need not be ordered before 1996 or 1997.

There is considerable disagreement about how many new powerplants will be needed by 2000. Those who believe that large numbers of new powerplants will be needed (several hundred GWs) anticipate rapid growth of electricity demand (3 or 4 percent per year), expect that large numbers of existing plants will be replaced because of deterioration in performance or retirement due to age and economic obsolescence, and expect only modest contributions from small power production (20,83).

On the other hand, some believe that no new powerplants or very few (a few dozen GW) will be needed before 2000 because they anticipate only slowly growing electricity demand (1 or 2 percent per year), expect little or no need to replace existing generating capacity, and expect substantial contributions to generating capacity from small sources of power such as cogeneration, geothermal, and small-scale hydropower (83).

This section lays out the range of possibilities from no new powerplants to several hundred gigawatts of new powerplants arising out of different combinations of growth in electric demand and varying utility decisions about powerplant retirements and use of small power sources.

The electric utility industry currently projects average growth in peak summer demand of 3.0 percent per year between 1982 and 1991 (68). * The industry has also planned for an increase in electric-generating resources of 158 GW by 1991 bringing the total generating capability up to 740 GW (68). Only 13 GW of scheduled retirements have been included in the 1991 estimate (69). At the same time the current reserve margin** of 33 percent is forecast to fall to 20 percent. As a rule, utilities like to maintain a reserve margin of 20 percent to allow for scheduled maintenance and repair and unscheduled outages. Individual regions may require higher reserve margins if they are poorly connected to other regions, if they are dependent on a small number of very large plants or if they are dependent for a large share of generating capacity on older plants or plants that burn expensive oil and natural gas.

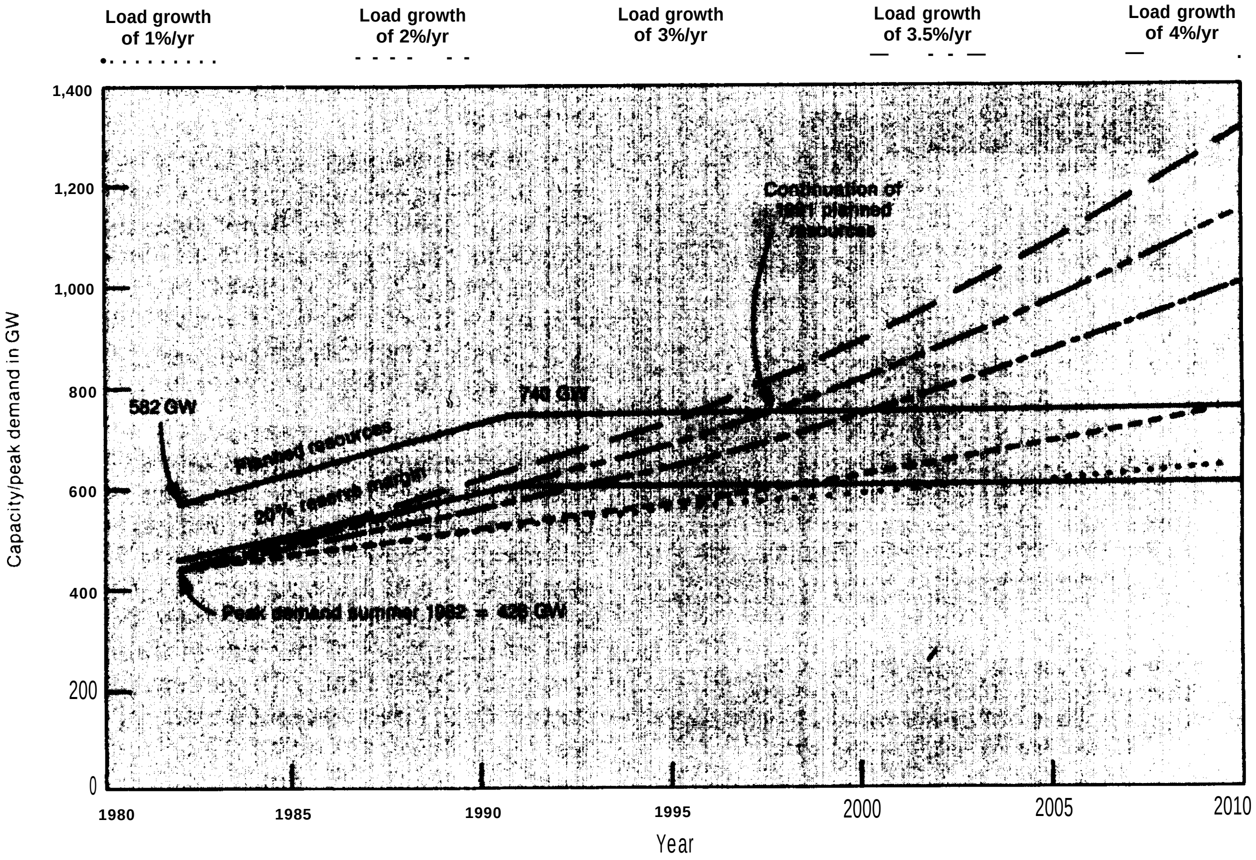
As shown in figure 7, the planned resources of 740 GW scheduled for 1991 would allow a reserve margin of 20 percent to be maintained until 1996 if electricity peak demand grows only at 2 percent per year, or until 2000 if electricity demand grows only at **1** percent per year. On the other hand, the average reserve margin will fall below 20 percent by 1987 if electricity demand increases at 4 percent per year.

However, the number of new powerplants that must be built to maintain a given reserve margin does not depend only on the rate of increase in

*This had dropped to 2.9 percent per year for 1983 to 1992 in the 1983 **North American Electric Reliability Council Forecast of Electric Power Supply and Demand (70).**

****'' Reserve margin" is defined as the percent excess of "planned resources" over "peak demand" where "planned resources" includes: 1) installed generating capacity, plus 2) scheduled power purchases less sales.**

Figure 7.—Projected Generating Capacity and Alternative Projections of Peak Demand



NOTE. "Planned resources" is defined by NERC to include: 1) Installed generating capacity, existing, under construction or in various stages of planning; 2) plus scheduled capacity purchases less capacity sales; 3) less total generating capacity out of service in deactivated shutdown status.
"Reserve margin" given here is the percent excess of "planned resources" over "projected peak demand."

SOURCE" North American Electric Reliability Council, Electric *Power Supply and Demand 1982-1997,* August 1982 and Off Ice of Technology Assessment

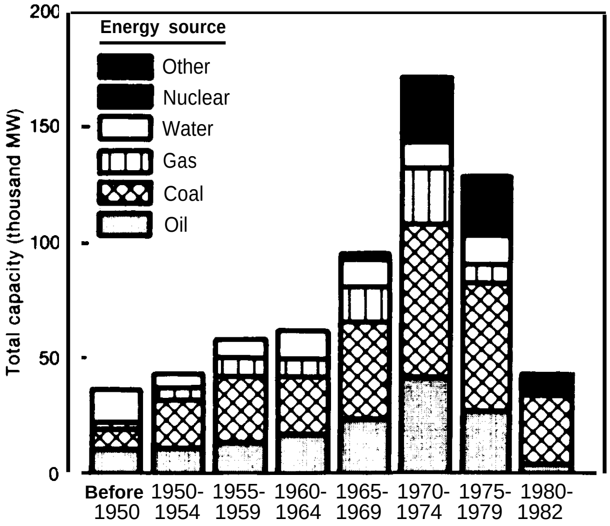
electric peak demand. It also depends on how much existing generating capacity must be replaced because powerplants are retired, due to age or to economic obsolescence, or because existing powerplants must be derated to lower electricity outputs.

Retirements Due to Age.–The "book lifetime" of a powerplant, used for accounting purposes, is usually 30 to 40 years. Over this period the plant is gradually depreciated and reduced as a recorded asset on the utility's books until, at the end of the period, it has no more book value and produces no return on capital. However, in practice powerplants may continue to operate for 50 years or more. As of 1982 there were about 10 GW of generating capacity that were more than 40 years old, more than a quarter of the total generating capacity that was in service 40 years ago.

In fact, the bulk of the current generating capacity of the United States is comparatively new. Over half has been built since 1970, as shown in figure 8. The number of plants that would be retired by 2000 varies greatly with the assumed plant life. In the unlikely event that a 30-year life would be used, over 200 GW would be retired by 2000 (see table 6). A 50-year schedule would retire only 20 GW.

Economic Obsolescence. -From 1965 **to 1979 a large number of steam-generating plants using oil or natural gas were built (see** fig. 8). They were

Figure 8.–The Energy Source and Age of Existing Electricity Generating Capacity



SOURCE: Energy Information Administration. Inventory of Power *Plants in* the *Ufnited States,* 1981 Data from the ‘Generating Units Reference File:

Table 6.—Possible Needs for New Electric. Generating Capability to Replace Retired Powerplants, Loss of Powerplant Availability, and Oil and Gas Steam Powerplants

	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 011 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 700/0 to:				
About 65%	21	**21**	**21**	**21**
About 600/0	**42**	*42*	*42*	*42*

SOURCE: Office of Technology Assessment.

ordered before the 1973 oil embargo. Under current price forecasts, oil prices are expected to remain fairly stable until the late 1980's or early 1990's and then increase substantially (by about 60 percent) from 1990 to 2000 (27). The price of natural gas to utilities is expected to increase steadily through the 1980's as the long-term contracts for natural gas sold at relatively low prices expire and are replaced by contracts for more expensive gas.

As of 1981, there were 152 GW of oil and natural gas steam-generating capacity. Together they totaled 27 percent of all generating capacity but produced only 22 percent of all electricity. As shown in table 7, oil-fired steam plants produced only half as much electricity relative to their share of generating capacity. Natural gas-fired steam plants, on the other hand, produced a greater share.

Even though oil and natural gas will be expensive, plants burning these fuels can be used as part of the reserve margin. Oil and gas are, in fact, just about 20 percent of two regions, the Southeast (SERC)* and the West (WSCC). The fraction of oil- and gas-generating capacity, however, is much larger than 20 percent in three regions: Texas (ERCOT) about 72 percent, Southwest Power Pool (SPP) about 56 percent, and the Northeast Power Coordinating Council (NPCC) about 51 percent (68). If oil and gas steam plants were retired continuously in these regions until they formed no more than 20 percent of total generating capacity, the total retired would be about 55 GW.

Loss of Availability of Generating Capacity.– The percent of time that nuclear and fossil baseload plants were available to generate electricity averaged around 70 percent** over the decade of the 1970's (67). If there were a reduction from 70 to 65 percent in the average availability of nuclear and coal powerplants this would be the equivalent of a loss of 21 GW out of a total current coal and nuclear-generating capacity of **294 GW (see table 6).**

A recent study for DOE assesses the prospects for changes in average availability **(82). Statistical**

***These are the regions of the Northeast Electric Reliability Council (NERC).**

****The availability figure used here is** *equivalent* **availability and includes service hours plus reserve hours less equivalent hours of partial outages. (66) From 1971-80, nuclear plants and coal plants over 575 MW averaged 67.8 percent in equivalent availability and coal plants from 200-574 MW averaged 74.3 percent in equivalent availability.**

Table 7.—installed Capacity and Net Electricity Generation by Type of Generating Capacity, 1981-82

	Installed generating capability, summer 1981 (GW)	Percent of total	Net electrical energy generation, 1981-82 (billion kWh)	Percent of total
Steam — coal	243	42	1,177	52
Steam — oil	89	16	190	8
Steam — gas	63	11	320	14
Nuclear power	51	9	274	12
Hydro electric	66	12	261	12
Combustion turbine — oil	34	6	3	—
Combustion turbine — gas.	6	1	7	—
Combined cycle oil	3	—	2	.
Other	17	3	26	1
Total	572	100	2,260	100

SOURCE **North American Electric Reliability Council,** *Electric Power Supply and Demand 1982-1991,* **August 1982.**

evidence from the past two decades would support an estimate of a loss of 3 to 5 percentage points of average availability for every 5-year increase **in average age of coal plants. Looking ahead, there could also be losses in availability of several percentage points** due to emission controls and requirements for low sulfur coal that is at the same time of lower combustion quality.

Offsetting these tendencies to reduced availability, however, there are also forces that might increase average availability. The utility industry has completed a period of construction of coal plants with poor availability, and the newest plants (from the late 1970's and early 1980's) should have substantially higher average availability. If this were to continue, overall availability could increase. If utilities invest in higher availabilities (e. g., by converting forced draft boilers to balanced draft), this will also increase availability (82). It is clear that attention to fuel quality and good management also can raise availabilities. Some Public Service Commissions (e.g., Michigan) are including incentives to improve availabilities in utilities' rate of return formulas.

On balance, it is unlikely that availability will increase or decrease dramatically. If a change in availability should occur, however, it would have a noticeable impact on the need for new capacity. A 10-percentage-point **change could imply an increased (or reduced) need for powerplants of** more than 40 GW by 2000.

Summary-The Need for New Powerplants.– the need for new powerplants depends on both the growth rates in electricity demand and on the need for replacement of existing generating capacity. Table 8 summarizes most of the range of disagreement and its implications for new powerplants. Estimates of growth in electricity demand range from 1 to 4 percent per year. (The table shows the implications of electricity demand growth rates of 1.5 to 3.5 percent.)

judgments about replacement of existing plants can, somewhat arbitrarily, be divided into high, medium, and low replacement. A high-level replacement of about 200 GW by 2000 would be necessary to: offset a slippage of about 5 percentage points in availability, meet a schedule of 40-year life expectancy for all powerplants, and retire about half the oil and gas capacity in this country (see table 6). A low-level replacement of 50 GW would meet a 50-year schedule, retire a little oil and gas capacity and would assume no slippage or an actual increase in average availability.

If these alternative replacement assumptions are combined with alternative growth rate assumptions (table 8), they lead to a wide range of needs for new plants. About 454 GW of new capacity would be needed, for example, by 2000 (beyond NERC's planned resources for 1991) to meet a 3.5 percent per year increase in peak demand for electricity **and** the high replacement re-

Table 8.—Numbers of 1,000 MW Powerplants Needed in the Year 2000
(beyond current utility plans for 1991)

Levels of replacement of existing plants	Electricity demand growth 1.5%/yr	2.5%/yr	3.5%/yr
Low: 50 GW; Replace all plants over 50 years old	9	144	303
Moderate: 125 GW; Replace all plants over 40 years old; plus 20 GW of oil and gas capacity	84	219	379
High: 200 GW; Replace plants over 40 years plus **95 GW of** oil and gas capacity	159	294	454

NOTES: 1. Planned generating capacity for 1991 is 740 GW, 158 GW more than 1982 generating sources of 582 GW. Starting point for demand calculations is 1982 summer peak demand of 428 GW.
2. The calculations assume a 20- percent reserve margin, excess of planned generating resources over peak demand.

SOURCE. Office of Technology Assessment.

quirements, as is pointed out in recent work at the Electric Power Research Institute (83). On the other hand, a low replacement requirement combined with only 1.S percent demand growth per year would require almost no new capacity.

This then is the dilemma for utility strategists. A shift of only 2 percentage points in demand growth combined with a more stretched out retirement schedule can reduce the requirement for new powerplants from hundreds of gigawatts (a number requiring a capital outlay of $0.5 trillion to $1 trillion 1982 dollars) to almost nothing. Some of the factors affecting utility choice of strategy, given this situation, are discussed in the next sections.

RATE REGULATION AND POWERPLANT FINANCE

Although the national average reserve margin will not dip below safe limits until well into the next decade, individual utilities may consider ordering powerplants before 1990 for any of three reasons: to replace expensive oil or natural gas generating capacity, to anticipate growth in their region, or to start a long leadtime plant well before it may be needed in the 1990's. This section describes the framework of rate regulation within which such a decision is made. The next section explores the broader strategic options for utilities.

Utilities' Current Financial Situation

Although the financial situation of utilities is improving slowly, they are still in a greatly weakened financial condition compared to their situation in 1970. The series of figures 9 through 14 prepared for the Department of Energy shows the origins of the financial difficulties of the 1970's until the relative improvement of 1982 (described below).

Utilities raised enormous amounts of capital in external financing in the 8 years from 1973-81, more than double the requirements of the telephone industry-the next most capital-intensive industry (fig. 9). In the process, more and more of utility assets became tied up in construction of new generating capacity (fig. 10), which equaled a quarter of all utility assets as of 1981. At the same time, even with high rates of inflation the nominal return on equity was kept constant. Thus the real value of utilities' return on equity declined sharply (fig. 11).

As a consequence of high inflation, enormous amounts of investment and large fractions of assets under construction, there was weakening of many indicators of financial health that are watched closely by investors. The amount of earnings paid out as dividends increased, leaving less for retained earnings to finance future projects. The ratio of operating income to interest on debt—pretax interest coverage—fell to disturbingly low levels. The cost of capital from issues of new stock and bond sales rose accordingly. After 1973, far more utility bonds were downgraded than upgraded; the number of utility bonds rated only "medium grade" BBB, increased from 10 to 43 (fig. 12). A lower rating usually means that investors require a higher yield in order to purchase the bond, and institutional investors may not be willing to purchase the bond at all (45). Similarly, the average market value of utility stock fell steadily from its high of about 2½ times book value in 1965, to a level equal to book value in 1970 **to less than** book value in 1974 (fig. 13). When stock sells below book value, there are two consequences. The utility must issue more stock, (and pay out more dividends) to raise each new unit of capital than the value of each existing unit of capital, and the value of stock for the existing stockholders is diluted. (See box A for a discussion of market-to-book ratio and stock dilution.)

One of the most serious problems for utilities has been a steady squeeze on cash flow. As shown in fig. 14, almost 50 percent of utilities' nominal return on equity was paper earnings in the form of allowance for funds used during construction (AFUDC). (See box B.) One result is that utilities have retained less and less of their earnings. The share of earnings paid to stockholders as dividends—the dividend payout ratio—increased from 68 percent in 1970 to 77 percent in 1981, For some companies it was above 100 percent, which means they paid out more than they earned (45).

In 1982 and 1983, there was some improvement in utility financial health. As of December 1983, market-to-book ratios were up to an average 0.98, and 51 out of 103 utilities had market-to-book ratios of more than 1.0 (59). Although more bonds are being downgraded than up-

Box A.—Market-To-Book Ratio and Dilution of Stock Value

When the stock of a utility is selling below its original selling price, the market-to-book ratio of the stock is below 1.0. This situation means that any sale of new stock at this lower-than-book price will dilute the value of the existing stock. This will be true even after the new asset begins earning at a full rate. The example that follows illustrates what happens when a utility's stock sells at half of book value, at book value, and at twice book value.

A utility goes into business by selling 1,000 shares at $10 each. The State regulatory agency allows the company to earn a 10 percent return. Ten percent on $10,000 is a $1,000 profit, which equals $1 a share. Now, let us say that the company has to raise $10,000 to build another powerplant and that the regulatory agency will let the utility earn another $1,000 (10 percent of $10,000) as soon as the plant is completed. Depending on the price at which the company sells new stock, the new financing reduces (dilutes), leaves unchanged, or increases earning per share. In the following table, we show what happens when new stock is sold at $5, $10, or $20.

	Market to Book Ratio		
	0.5	*1.0*	*2.0*
Sale price	$5	$10	$20
Net income before completion of new powerplant	$1,000	$1,000	$1,000
Net income earned on new powerplant	1,000	1,000	1,000
Total new income	$2,000	$2,000	$2,000
New shares sold to raise $10,000	2,000	1,000	500
Old shares	1,000	1,000	1,000
Shares outstanding after the offering	3,000	2,000	1,500
Earnings per share	$0.67	$1.00	$1.33

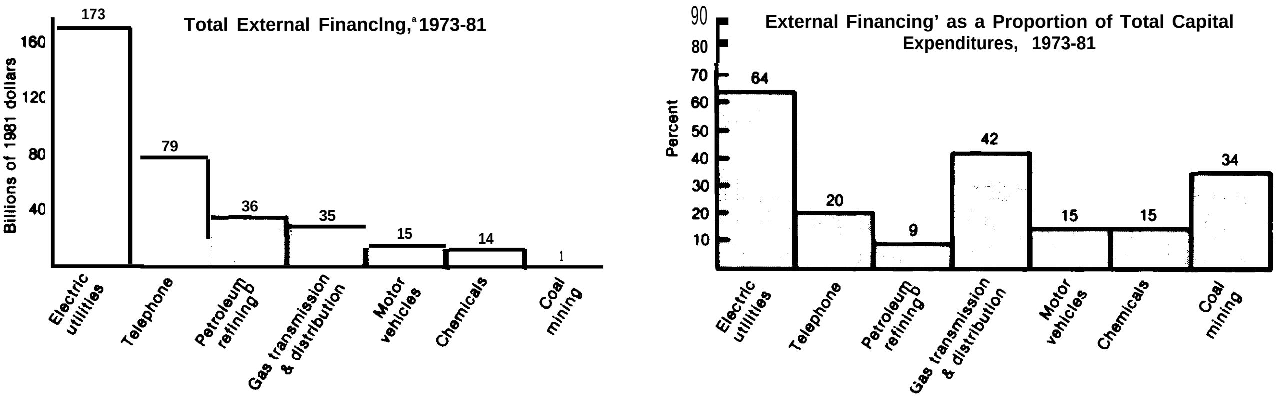
Note that when the stock has to be sold at a low price ($5), earnings per share fall from $1.00 to $0.67 after the offering, despite the rise from $1,000 to $2,000 in the utility's income after the new plant goes into service. In the second example, earnings per share are not diluted by the offering. In the third, they are actually improved.

Electric utility companies often need to sell stock to finance their capital expenditures. When shares are to be sold at low prices, such as those that currently prevail, financing is diluting. Thus, large capital expenditures at a time of low stock prices may be detrimental to current shareholders. That is one reason why many financial experts view a slowdown in utility spending as favorable for shareholders.

SOURCE: Adapted from a description in Hyman and Kelley, *The Financial Aspects of Nuclear Power: Capital, Credit, Demand and Risk*, American Nuclear Society, Dec. 3, 1981 (47).

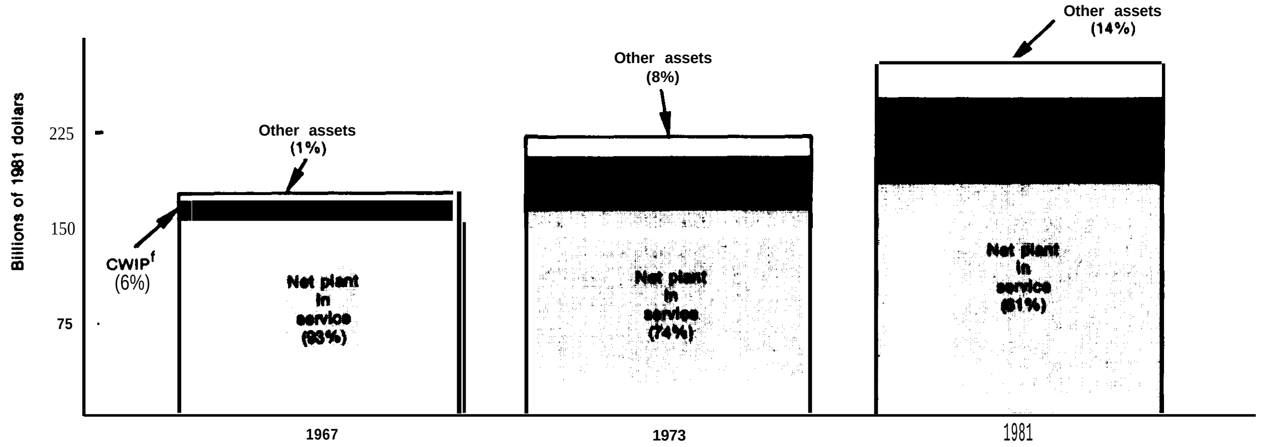
The History of the Deterioration in the Financial Health of Electric Utilities, 1960=82

Figure 9.—The Electric Utility Industry is Dependent on Externally Generated Funds to a Greater Extent Than Other Large Capital Users



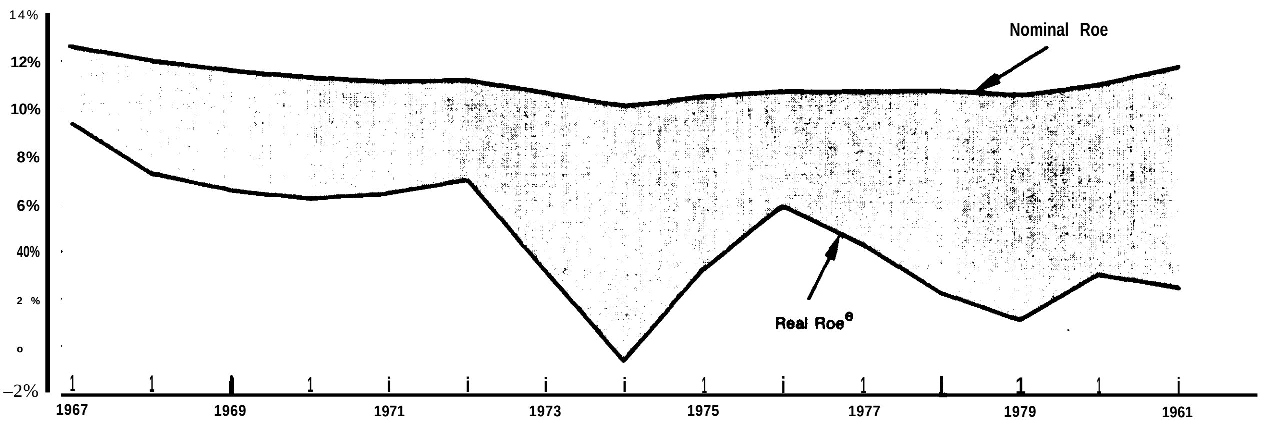
[a] Net of debt retirements.
[b] Includes exploration and production by companies primarily involved in refining.

Figure 10.–Since 1967, the Fraction of Utility Assets Tied Up in "Construction Work in Progress" Has Steadily increased



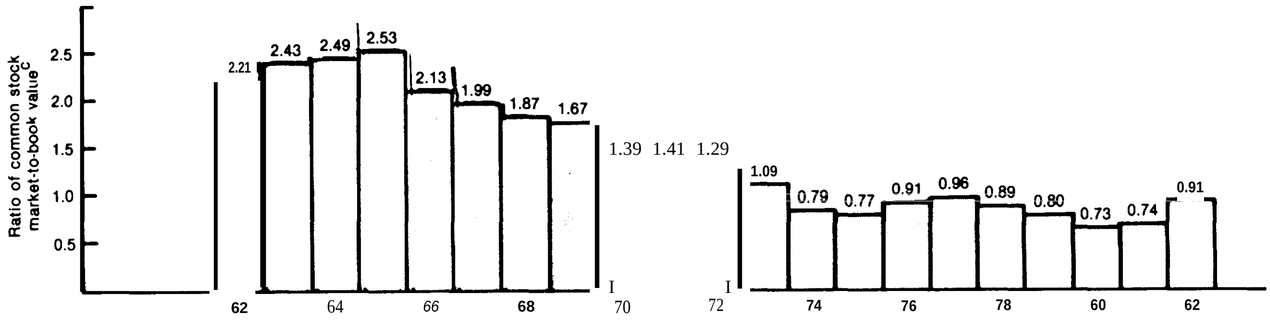
[f] Construction work in progress (CWIP) refers to plant being built, but not Yet in service.

Figure 11.— Beginning in 1972, the Utilities' Real Return on Equity Has Been Eroded by Inflation (utility Industry annual average return on common equity (end of year))



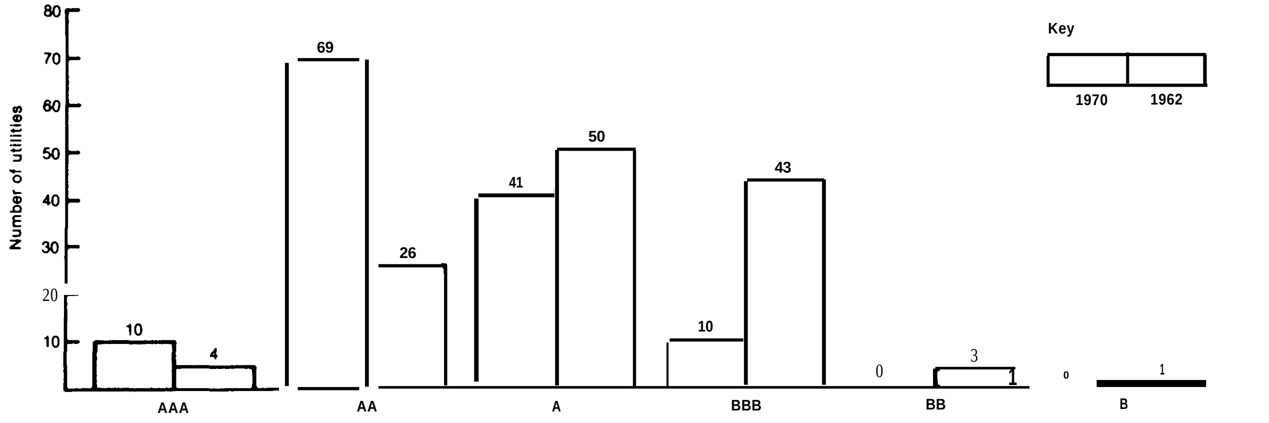
[e] Nominal Roe deflated by GNP implicit price deflator (measured at fourth quarter annually).

Figure 12.—Since 1973, the Average Utility Stock has Sold Below its Book Value[a]



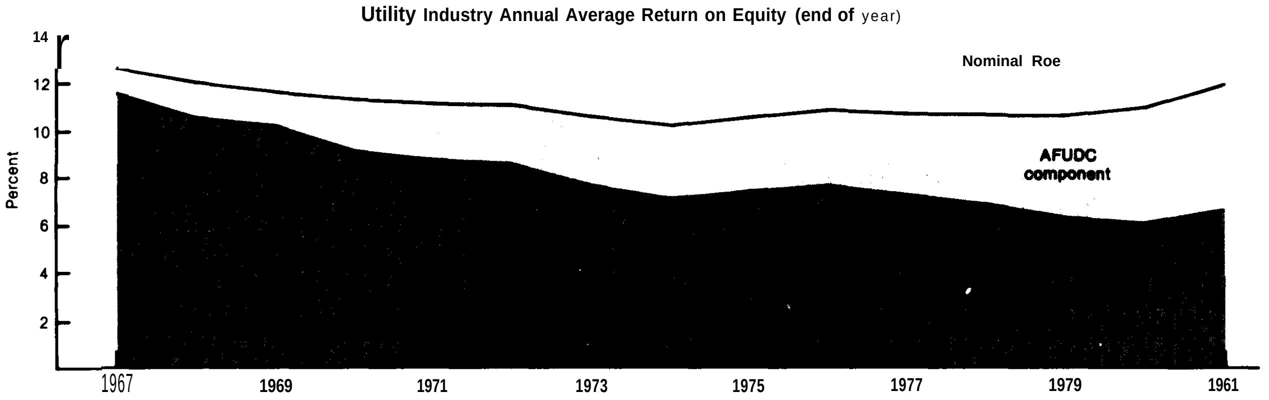
[c]Average of high and low value for the Year.
'August 1962.

Figure 13.—In 1970, A Majority of Utilities Were Rated AA or Better in 1982, a Majority Are Rated A or Worse



[a]See box A for an explanation of the implications of stock selling below book value.

Figure 14.-Over Time, the Share of AFUDC in Total Earnings Has Increased and the Share of Cash Has Fallen



SOURCE: Booz-Allen & Hamilton Inc., *The Financial Health of the Electrlc Utility Industry,* prepared for the Department of Energy October 1962, using data from Utility Compustat; U.S. Department of Commerce, *Survey of Current Business;* Edison Electric Institute, Statistical *Yearbook of the Utility Industry;* Standard and Poor's Bond Guide; Energy Information Administration, *Statistics of Privately Owned Utilities.*

[illegible]

graded, the number of net downgradings has been reduced sharply. By late 1983, the average earned return on common equity for the 100 largest electric utilities was up to 14.1 percent, more than 200 basis points higher than the earned return in 1980 (59).

Implications of Utilities' Financial Situation

There are two ways of looking at the current financial situation of the utilities and the incentives to build more plants. From one perspective the electric utilities have shared in general economic problems and have not fared as badly as some industries. The market-to-book ratios of all industrial stocks fell over the 1970's, although on average the industrial stocks stayed well above a market-to-book ratio of 1.0. For the first part of 1982, the return on investment of the electric utilities ranked 14th out of 39 industries, well above the average for such industries as chemicals, appliances and paper (41).

From this point of view, there is no need for further concern about near-term utility solvency. The worst of the utilities' problems are coming to an end, and their financial situation should improve gradually. Public utility commissions (PUCs) have responded by increasing the allowed rate of return to utilities, and the Federal Government has provided additional relief from cash flow shortages in the 1981 Economic Recovery Tax Act through liberalized depreciation allowances. The tax law further mandates that these must be "normalized" (retained by the utility) rather than "flowed through" to the consumer in lower electricity rates. Further relief for those utilities, with problems selling their stock to finance large construction programs, has also been available from the 1981 Tax Act benefits for reinvestment of dividends in purchases of new utility stock. Over the next few years, external financing needs should diminish gradually, as total construction expenditures decrease slightly and internal funding–from retained earnings, depreciation and deferred Federal taxes–increases.

From another perspective, however, there is still cause for concern. Inflation has brought about several distortions in the ratemaking process that may need to be corrected before the next round of orders for new generating capacity. From this point of view, the issue is not whether utilities need rate relief to keep from going bankrupt, but whether the treatment of capital in rate regulation needs to be adjusted for the impact of inflation in order to prevent allocation of utility resources away from capital-intensive electricity-generating processes—beyond the point where **it** would be beneficial to the ratepayer.

It is not enough, from this perspective, for utilities to recover their financial strength during the coming decade of slowed construction programs. In the 1990's, **when the utilities need capital again** for construction, investment advisors will have models that predict a deterioration in financial health associated with a large construction program unless rate regulation can be expected to give an adequate return on capital right through the construction period.

The concern that electricity rate regulation needs to be adjusted for the impact of inflation can be summed up in several points. The first problem is erosion in the definition of cost of capital. Back in 1962, electricity demand was growing rapidly. There was relatively little inflation, and unit costs of generating electricity were decreasing. Utilities were allowed an average 11.1 percent return on equity and actually earned slightly more than that—about 11.3 percent—right in line with the average of Standard & Poor's 400 industrial stocks (45).

By 1973, this situation had changed. Demand for electricity was growing more slowly, inflation had increased greatly, and the unit costs of producing electricity had begun to increase. From 1973 to 1981, the return on equity earned by utilities (10.9 percent) fell substantially below the return on equity allowed by State PUCs (1 3.3 percent). Although the allowed return came close to the return on equity earned by the 400 industrials (14.3 percent), the earned return fell well below. If the return on equity is designed to exclude AFUDC-deferred paper earnings, it fell far below the return on industrials (see fig. 14).

For utilities to earn a return on equity significantly below that earned by industrial stocks represents a change from past regulatory practice. The basis for determining rate of return has its legal foundation in two cases–the 1923 *Bluefield Water Works** case and the 1944 Hope *Natural Gas Co.* case.** These cases established three principles:

1. the utility can charge rates sufficiently high to maintain its financial integrity;
2. the utility's rates may cover all legitimate expenses including the cost of capital; and
3. the utility should be able to earn return at a rate that is comparable to companies of comparable risk.

Although in principle PUCs allowed rates of return on equity comparable to companies of comparable risk, in practice they failed to adapt rate regulation practices to accommodate inflation. The practice of using an historical test year rather than a future year to determine income and expenses is one example. Politically, it often was difficult for PUCs to grant full rate increases requested by utilities when inflation caused them to return year after year. As precedents accumulated in each State it became harder for individual Commissioners to argue for a restoration to the full Hope/Bluefield definition of cost of capital. * * *

● ***Blue field Water Works and Improvement Co. v. West** Virginia* *Public* ***Service Commission, 262*** **'US 679, 692** PUR **1923D** 11.

*****Federal Power Commission*** v. ***Hope Natural Gas Co. (1944), 320*** **US 591, 60351** PUR **NS 193.**

*****It is in this context that one Wall Street participant in an OTA workshop recommended a high-level commission of rate regulators, utility executives, and investment advisors to reexamine the** Hope/Bluefield **principles, determine the problems of implementing the principles in times of inflation, and make recommendations that take into account the political realities of a Federal system.**

A second problem, exacerbating the first, is that of "rate shock" which arises from the front-end loading of rate requirements for large capital investments. This phenomenon (explained in box C) is noticeable at low rates of inflation and is striking at high rates of inflation. Assuming 7 percent inflation, for example, the cost of electricity in constant dollars from Nuclear Plant X shown in box C would be 9.5¢/kWh the first year and only 1.5¢/kWh the 20th year. For large plants entering the rate base of small utilities, the increase can be 20 to 30 percent the first year. This problem is exacerbated the more AFUDC (see box B) is included in the cost of the plant as it enters the rate base. (AFUDC is described further in the next section on the risks of constructing nuclear plants because the impact of AFUDC is largest for plants with the high capital cost and long duration of nuclear plants.)

The combination of the very high rate requirements in early years and low rate requirements in subsequent years discourages multidecade planning of generating capacity. While short-term rate increases must be tolerated to realize long-term reductions in real electricity rates, there are intense political pressures on public utility commissioners to hold down these short-term rates (88).

A final cause for distortion in utility rate regulation is the generally practiced fuel pass-through which allows utilities to pass changes in fuel prices onto consumers without going back to the PUC for an increase in rates. This has been a useful device for avoiding damage to utility cash flow from the volatile changes in fuel (oil and natural gas) prices in the 1970's but it has had the inadvertent effect of shielding utilities from the effects of inflation in fuel costs while they have not been shielded from increases in the cost of capital. For a utility faced with capital expenditures to avoid fuel costs—through rehabilitating a plant, building a new one, or investing in load management—there is a theoretical incentive to stick with the fuel-burning plant as long as fuel costs are recovered immediately and capital costs are recovered late and not fully.

Many utilities continue to base their generating capacity decisions on what will minimize lifetime costs to ratepayers. However, some utilities are beginning to say openly (seethe later discussion of utility strategies) that they are attempting to minimize capital requirements rather than total revenue requirements, to protect the interests of their stockholders to the possible long-term detriment of the ratepayers.

Possible Changes in Rate Regulation

There have been many specific proposals for utility rate regulation. Some are designed to encourage conservation, load management, or the rehabilitation of existing powerplants. Others are designed to encourage the construction of new powerplants, especially when they are intended to displace powerplants now burning oil or natural gas.

This assessment does not deal with the complex subject of rate regulation reform in any detail. However, it is useful to describe briefly some of those reform proposals that are specifically intended to offset those aspects of rate regulation that discourage capital-intensive or risky projects. These reform proposals would be most likely to improve the prospects for more orders of nuclear powerplants.

Construction Work in Progress (CWIP).–The simplest of the proposed changes in rate regulation is to allow a large fraction or all of a utility's CWIP in the rate base. CWIP is advocated because it reduces or eliminates AFUDC. This in turn increases utility cash flow and the quality of earnings and reduces the likelihood of rate shock because the rate base of the new plant includes little or no AFUDC.

One argument for including CWIP in the rate base is that electricity rates come closer to reflecting the true cost of incremental electricity demand, providing a more accurate incentive for conservation. Opponents of CWIP in the rate base, however, fear that utilities will lose the incentive to keep plant costs down and to finish them on time. Furthermore, opponents claim, utilities may return to overbuilding. Many PUCs have responded to these concerns by including only a portion of CWIP in the rate base (62).

Phased-in Rate Requirements. -At least six States have developed methods of phasing in the rate requirements for large new nuclear power-

Box C.—Utility Accounting and the Origins of "The Money-Saving Rate Increase"[1]

The conventions of utility accounting have created a dilemma that affects all investment choices between a capital-intensive plant (e.g., a nuclear or baseload coal plant) and a fuel-intensive plant (e.g., a combustion turbine or an oil or gas steam plant}. if two plants (one of each type) have equal levelized annual cost, and equal lifecycle cost, the capital-intensive plant will cost consumers far more in early years and the fuel-intensive plant will cost far more in later years. This situation causes a dilemma for oil- and gas-using utilities who wish to substitute coal or nuclear plants for their oil or gas plants. When their analysis convinces them that the lifecycle cost of the coal or nuclear plant will be less, they still must face a "money-saving rate increase" to cover the early years extra cost of the capital-intensive plant.

An Example. The dilemma is illustrated by a specific example in table Cl. A nuclear plant called Nuclear Plant X has been constructed for $2 billion (including accumulated AFUDC) and is about to be placed in service to replace an oil plant that produces the same amount of electricity. The oil plant is old and fully depreciated and earns no return to capital. When the nuclear plant goes into service there will be a net fuel saving the first year of $263 million, which equals the value of oil saved less the cost of nuclear fuel for the nuclear plant. At the same time, accounting and ratemaking conventions dictate that the first-year capital charge for the nuclear plant will be $471 million, or $208 million more than the fuel savings. In the fifth year the capital charge has dropped to $364 million, less than the fuel savings for the first time (if the cost of fuel escalates at 9 percent per year), and by the eighth year the cumulative capital charge of the nuclear plant will be less than the cumulative savings resulting from lower fuel costs. In the 15th year, the nuclear plant costs only $268 million in rate requirements and saves $878 million in fuel costs.

If fuel costs escalate more slowly (at only 5 percent per year), the results are shown in the right-hand columns in table Cl. Annual capital charges for Nuclear Plant X drop below annual fuel savings during the sixth year and Nuclear Plant X breaks even on a cumulative basis by the 12th year. In both cases, Nuclear Plant X will cost less over the 30-year life of the plant (if a discount rate of 12 percent is used). In the first case (with 9 percent fuel escalation), Nuclear Plant X will cost about $3.1 billion in lifetime discounted rate requirements and will save $5 billion. In the second case (with 5 percent annual fuel cost escalation), Nuclear Plant X will save $3.5 billion. In both cases the electricity ratepayers would be better off with Nuclear Plant X over the long run. However, consumers would be worse off in the short run, because of the high capital charges at the beginning of plant operation, which translate into high electricity rates.

Two Other Examples. To take another example of this phenomenon, which is sometimes referred to as "front-end loading" of capital costs, suppose another Nuclear Plant Y, with identical construction cost (in 1982 dollars) as Nuclear Plant X had been placed in the rate base 8 years before, in 1974. By 1982, the capital charge for Plant Y in the eighth year of operation would have diminished so much (using the same schedule of capital charges) that it would cost $0.03/kWh while the first-year capital charge for Nuclear Plant X, put in service in 1982, would be $0.09/kWh. Part of the reason for the difference is that the book value (see explanation below of Plant Y is only $1.1 billion, the equivalent in 1982 dollars to the $2 billion cost of Nuclear Plant X. The rest of the difference is that the capital charge for the eighth year is only 0.15 of the original cost; compared to 0.24 in the first year.

In still another example, if Nuclear Plant X is replaced in its 30th year of operation by another identical plant, the first-year capital charge for that plant will& $3.6 billion, more than 20 times the capital charge of $170 million in the 30th year of Nuclear Plant X.

Why Utility Accounting Practice Produces This Result. T he main reason for this result is that the value of a plant is carried at original cost (book value) not at replacement cost (market value) on a utility's books. The annual capital charge used in computing rate requirements has a series of components,

[1]The analysis in this box is based on two articles by Sally Hunt Waiter, "Trending the Rate Base," *Public Utilities Fortnightly*, May 13, 1982, and "Avoiding the Money Saving Rate Increase," *Public Utilities Fortnightly*, June 24, 1962.

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all of which require multiplying some percent times original cost. These components include: return on equity investment (a percent return times the book value of equity investment), debt service (percent of book value borrowed), depreciation (a percent each year times the book value of the asset), and property tax (a percent times book value). Furthermore, as the plant is depreciated, the book value of the plant is reduced by the amount of the depreciation. A simplified example is illustrated in figure C1. The original (book value) rate base of $1,000 is reduced each year by the amount of depreciation and drops to zero in the 20th year. The current earnings are calculated at 0.12 times the depreciated rate base, and they are reduced as the rate base is reduced.

Alternative Accounting Practices. In its simplest form, the chief proposal for alleviating the distortions in decisionmaking caused by the phenomenon of front-end loading of capital charges, is to replace the use of original cost (book value) in the calculating of capital charges, with a calculation closer to replacement cost. The conceptually simplest of these calculation methods is called "trended original cost" because it increases the value of the rate base (asset) in keeping with the trend in general prices, and does not require a calculation of the market value of the asset. With a trended original cost rate base, the method for calculating the rate of return changes. Because inflation is taken care of in the reevaluation of the rate base, inflation is removed from the rate of return, and the real rate of return is used instead of the nominal rate. Depreciation charges are also changed. They are set to increase with the nominal interest rate. These changes ensure that the discounted lifecycle revenues of both methods are the same.

A specific example is illustrated in figure C2. The original rate base of $1,000 is increased each year by 0.07, the assumed rate of inflation. Then the year's depreciation charge is subtracted. The rate base gradually increases (in current dollars) until the ninth year and then it starts to drop until it reaches zero in the 20th year. Current earnings are calculated at 0.05 of the rate base, and are much lower in the early years under this method than under original cost accounting. Depreciation starts lower but eventually reaches a substantial sum in the 20th year, providing cash flow at the point when the plant should be replaced. As is clear from figure C2, the total revenue requirements for the nuclear plant increase in keeping with the general increase in prices. The present value of both revenue streams and therefore consumer payments is exactly the same at a discount rate equal to the nominal interest rate.

Table C1.—Revenue Requirements and Fuel Savings for Nuclear Plant X

Year from entry in service	Revenue requirements for nuclear plant	Fuel savings at $35/bbl oil with 9% escalation			Fuel savings at $35/bbl oil with 5% escalation		
		Fuel savings	Net savings (2) – (1)	Cumulative savings	Fuel savings	Net savings (5) – (1)	Cumulative savings
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
				(millions of dollars)			
1	471	263	–208	–208	263	–208	–208
2	425	286	–139	–347	276	–149	–357
3	403	312	–91	–437	290	–113	–470
4	383	340	–43	–480	304	–79	–549
5	364	371	7	–473	319	–45	–594
6	348	404	56	–417	335	–13	–608
7	333	441	108	–309	352	19	–587
8	320	480	160	–149	370	50	–537
9	309	524	215	66	388	79	–458
10	299	571	272	338	408	109	–349
11	291	622	331	669	428	137	–212
12	286	678	392	1,061	449	163	–49
13	280	739	459	1,520	472	192	143
15	268	878	610	2,682	520	252	617
20	288	1,351	1,063	7,018	664	376	2,263
25	231	2,079	1,848	14,583	848	617	4,846
30	174	3,199	3,025	27,141	1,082	908	8,779

ASSUMPTIONS: Revenue requirements for each of 30 years based on: return on common equity = 14%; debt cost = 11%; insurance, property taxes, and replacement = 1.95%; normalized investment tax credit and accelerated depreciation and 10-year ADR life, with a 30-year life.

Figure Cl.—Rate Base and Revenue Requirements Under Original Cost Accounting

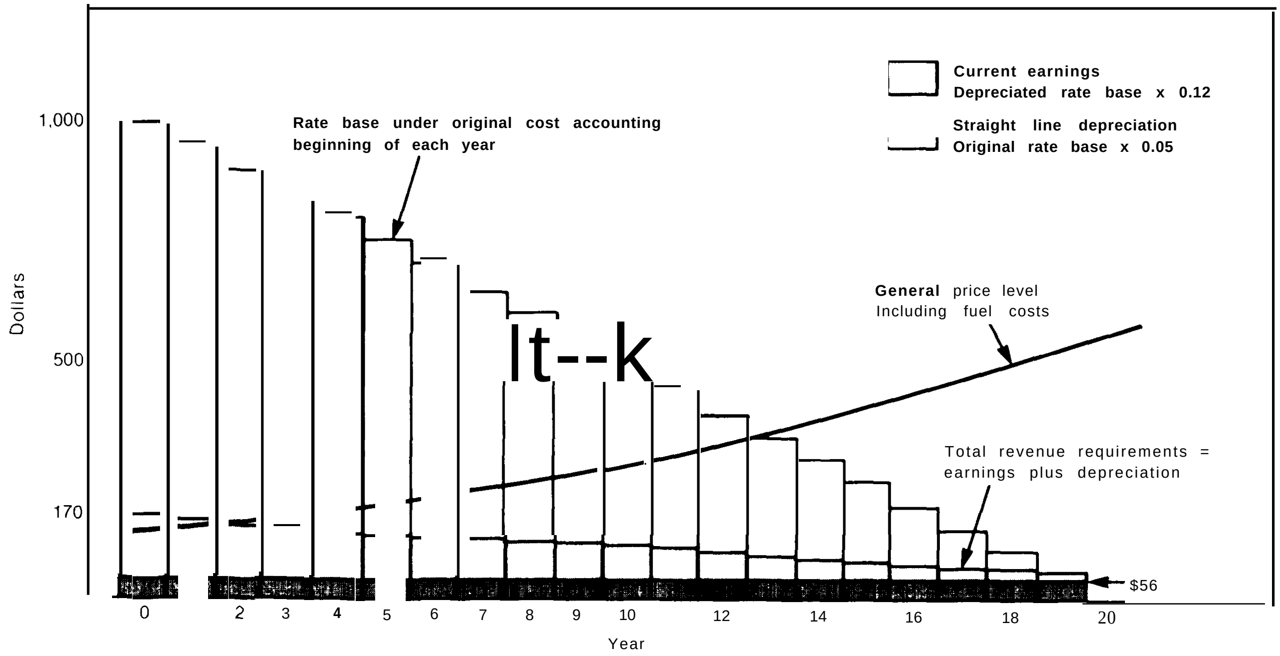
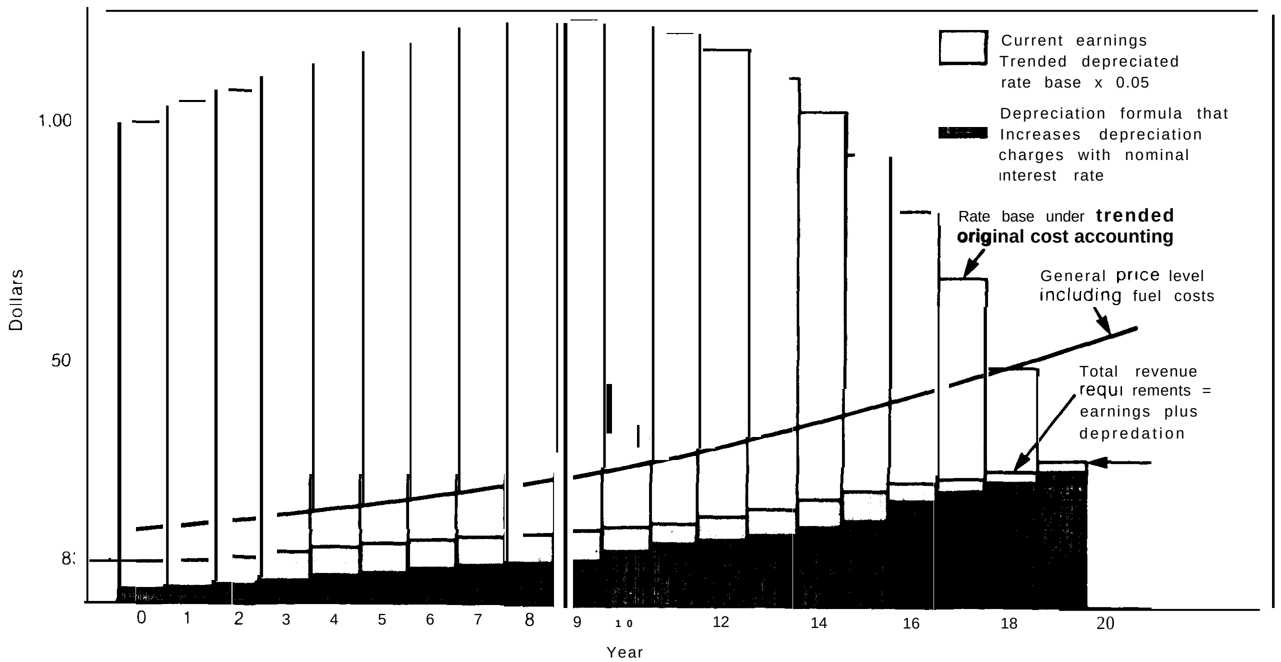


Figure C2.-Rate Base and Revenue Requirements Under Trended Original Cost Accounting



plants which would cause significant early year rate increases under conventional rate treatments (75). Two of these (New York and Illinois) have developed plans for "negative CWIP." Under these schemes, some CWIP is allowed in the rate base for several years before a plant comes online and then an equal amount is subtracted from the rate base for the first few years after the plant comes online. After the first few years the rate base returns to what it would have been in the absence of any CWIP.

Pay-As-You-Go for Inflation Schemes.—Recently, a series of proposals have been made to adapt the sequence of rate requirements for a capital-intensive plant, (e.g., a nuclear plant) more explicitly to inflation (54,88). In effect, these proposals would eliminate the front-end loading of capital return for capital-intensive plants in time of inflation and replace the "downward slope" of annual rate requirements in constant dollars (shown in fig. Cl in box C) with a horizontal or gentle upward slope more like the sequence of annual rate requirements for an oil plant (shown in fig. C2 in box C).

Some of these proposals would do this directly by using a rate of return net of inflation and adjusting the rate base for inflation (this is called "trended original cost" ratemaking in contrast to "original cost" ratemaking), Others would do it indirectly by deferring certain operating or depreciation expenditures until later so as to approximate an upward slope of rate requirements.

The Obstacles to a Long-Term Commission Perspective.– In principle, these latter proposals would all make it easier for PUCs to increase the authorized real return on equity because rate increases for new powerplants are less likely. Increasing the authorized return should in turn improve the incentives for constructing new powerplants when it is in the long-term interests of the ratepayers. All these proposals, however, rely on an implicit agreement between investors and PUCs that a particular way of determining revenues will be maintained over decades. Under Trended Original Cost schemes, utility investors accept a lower rate of return in early years with the promise that the rate base will be fully adjusted for inflation. Under indexed rate of return schemes, investors accept a somewhat lower than market rate of return as interest rates are going up, in return for enjoying a somewhat-higher-than-market rate of return as interest rates are coming back down.

It is just this implicit agreement that seems to be missing from today's rate regulation procedures. in some cases, the PUC may be willing to work out a sensible approach to rate determination over the long term, but is blocked by the State legislature. The Indiana PUC, for example, introduced a graduated rate increase incorporating trended original cost principles to bring Marble Hill, a large nuclear plant, into the rate base of Indiana Public Service. The plan was explicitly blocked by the State legislature. Eight States, by vote of the State legislature or by referendum, have banned CWIP inclusions in utility rate bases for just the reasons described above (41).

Furthermore, commissioners may lack the time or motivation to grasp the long-term view. Pennsylvania is one of the few States with 1()-year terms for its appointed commissioners. Many States have reduced PUC terms of 6 or longer to 4 or 5 years. An increasing number of States have elected rather than appointed commissioners. For most commissioners, electric utility rate cases are only a few among hundreds or thousands of cases from local as well as statewide utilities, that provide water, sewer, telephone, and gas as well as electricity. Often, electric utilities and their consumers must take time to educate commissioners about the issues surrounding electricity supply, demand and rates over the long term.

It is interesting to note (see ch. 7) that the United States is the only one of all the major developed countries with a Federal system in which retail electricity rates are regulated at the State level. In many countries, electricity rates are unregulated. In West Germany, State electric authorities set their own rates subject to Federal approval. In the United States, State regulation leads to the result that the cost of utility capital (return on equity) varies among the different States from 12 to 17 percent, even though the market for capital generally is recognized as national. Because of the strong U.S. Federal tradition, however, any proposals for regional or Federal determination of the cost of capital or other regulation on State regulation must be developed in the context of longstanding legal traditions about the Federal regulation of commerce.

The Impact of Changes in Rate Regulation in Electricity Prices.–Changes in rate regulation to increase the return to capital, utility cash flow, and/or quality of earnings, in turn would increase electricity rates. How much rates would increase is important to know for two reasons. **It** would help to weigh current consumer interests against future consumer interests. It would help also to identify the likely future course of electricity prices and the resulting impact on electricity demand. Uncertainty about future electricity price increases is a key source of uncertainty about how much electricity demand will increase.

Most of the attempts to estimate the impact of changes in rate regulation on electricity rates have focused on regions (48,85). There appears to be minimal impact on average regional electricity prices from increasing the return to capital and including CWIP in the rate base—an increase in average regional electricity prices of 2 to 3 percent. Regional analysis of rate impacts, however, combine the experiences of quite different utilities.

For two individual utilities, examined as case studies in a recent analysis, the impacts of rate regulation changes would be significant but fairly short-lived (2). Increasing the average rate of return in 1982 from 12 to 16 percent, for example, would have caused a 1 -year increase of 3.3 percent in the rates of a Southeastern utility and a 6.2-percent increase in rates for a Midwestern utility. Rates would have stabilized in the following years.

The impact of CWIP on rates is estimated to be greater but also fairly short-lived. Including CWIP in rate base in 1982 would have increased rates 5 percent for the Southeastern utility and **14.2** percent for the Midwestern utility. Eight years later, however, in 1990, the rates would be only 0.4 percent higher than without CWIP for the Southeastern utility and would actually be lower for the Midwestern utility. Although short-lived, the increase in rates is large enough that there would be a substantial impact on electricity demand, spread out, to be sure, over a number of years.

Before PUCs can tackle fully the long-term implications of possible rate regulatory changes, it would be useful to have a more complete understanding of the impacts on rates and potential demand responses.

Conclusion.– Because of the financial deterioration experienced in the 1970's, utilities do not have the financial reserves that they had in the late 1960's and must therefore pay more attention to the impact of their future construction programs on their future financial health. Although their finances are improving, utilities are likely again to find themselves in weakened condition similar to that experienced in the 1970's if they embark on another round of large-scale construction later this century. This is especially true if inflation increases again and exacerbates the impact of AFUDC and the front-end loading of rate requirements for such capital-intensive projects as nuclear plants.

The last section of the chapter discusses utility strategies. One element of choice for both utilities and PUCs is the tradeoff between short-term price increases from rate regulation policies designed to be more attractive to capital and longer term price decreases projected to come about from construction of central station powerplants (including nuclear) which are expected to be the lowest cost source of baseload power over their lifetimes.

THE COST OF BUILDING AND OPERATING NUCLEAR POWERPLANTS

In addition to the bias against capital-intensive generation caused by current ratemaking practice, investors and utility executives cite several major financial reasons to be wary of investing in nuclear powerplants. First, the cost of building a nuclear powerplant has increased rapidly over the **past** decade. The estimated cost of the average nuclear plant now being completed is so high that the average coal plant, in most cases, would produce electricity more cheaply over a lifetime (although in most regions the lowest cost nuclear plants are still competitive with coal plants). Second, the average construction time* of a nuclear plant has increased much faster than the average leadtimes for a coal plant, and this makes it harder for nuclear plants than coal plants to match demand. Third, since the Three Mile Island accident, it has been widely recognized that a major accident can disable an entire plant for an extended period of time and require more than $1 billion in cleanup costs, as well as other expenses to restart the plant and pay for replacement power. Major disabling accidents at coal plants are both less likely and less costly to cleanup and repair. Finally, the current political climate for nuclear (described in ch. 8) is a major source of financial risk. The output of a several billion dollar investment in a plant could be lost for a year or more if regulatory commissions refuse to put it in the rate base, or if a statewide anti-nuclear referendum passes and the plant is shut down. Nuclear accidents or near-accidents in plants owned by other utilities can lead to a new series of safety regulations (discussed further in ch. 6) requiring backfits that may cost a sizable fraction of the original cost of the plant.

The Rapid Increase in Nuclear Plant Cost

In the early 1970's, nuclear powerplants were completed for a total cost of about $150 to $300/kW. ** As of 1983, seven nuclear powerplants almost complete and ready to come online will cost from $1,000 to $3,000/kW, an increase of 550 to 900 percent. General inflation alone would account only for an increase of 115 percent from 1971 to 1983. Inflation in components of (labor and materials) used to build nuclear powerplants*** would account for a further increase of about 20 percent.

*Defined as follows: *for nuc/carp/ants,* issue of construction permit to commercial operation; *for coal plants,* order of boiler to commercial operation.

**In "mixed" dollars, see explanation below.

***As measured *by the* Handy-Whitman index. See below.

Several attempts have been made to document and understand the increase in cost of nuclear power over the past decade (6,7,1 7,37,55,61 ,76). The task is difficult because the cost data cited above cannot be used for comparing plants over time. The above estimates are composites of construction expenses paid in different years with different dollar values, referred to as "mixed" dollars. Most also include some interest that has been deferred during construction, capitalized, and added to the total capital cost (see box B in the previous section on CWIP and AFUDC). The amount of interest that is capitalized varies from State to State and interest rates vary from year to year.

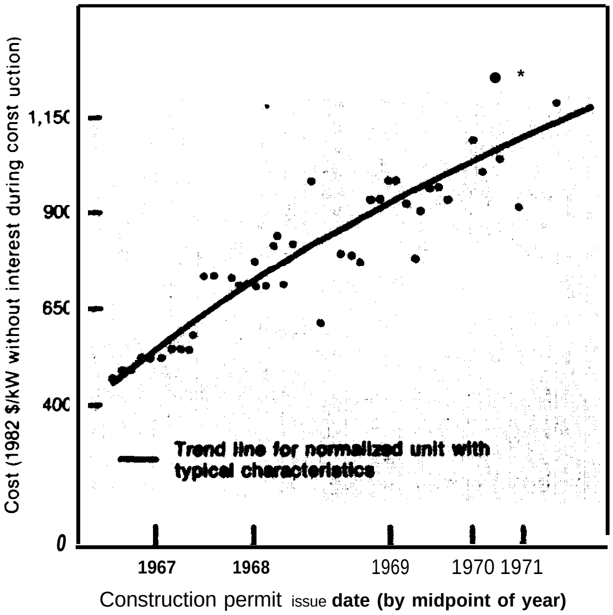
The increase in costs of nuclear powerplants through the 1970's was analyzed in a carefully documented study by Charles Komanoff (55). The costs exclude interest during construction and were adjusted for inflation, permitting comparisons from year to year. * Figure 15 is a plot of the costs per kW (expressed in 1982 dollars) of individual powerplants with construction permits issued from 1967 to 1971. (It is more accurate to group the different generations of nuclear powerplants by start date than by completion date. Later completion dates, by definition, will have a disproportionate share of the delayed, and therefore probably more expensive, plants.)

For plants with construction permits issued around 1967 (and generally completed in 1972-74), the direct costs in 1982 dollars ranged from $400 to $500/kW. For plants with construction permits issued 3 years later, in 1970-71 (and completed in 1976-78) the direct cost in 1982 dollars had more than doubled to $900 to $1,300/kW.

A comparable analysis by Komanoff of the costs of plants currently under construction has been completed but will not be published until early 1984 (56). Preliminary results show that the cost of a typical plant continued to increase, and the range of cost experiences also has increased since the early 1970's. Figure 16 compares "typical" plants completed in 1971 and 1978 (these are

*As described in Komanoff's *Powerplant Cost Escalation (55)* app. C, a standard pattern of cash payments was assumed for each plant and then deflated using the Handy-Whitman index developed to make inflation estimates of components used in powerplants.

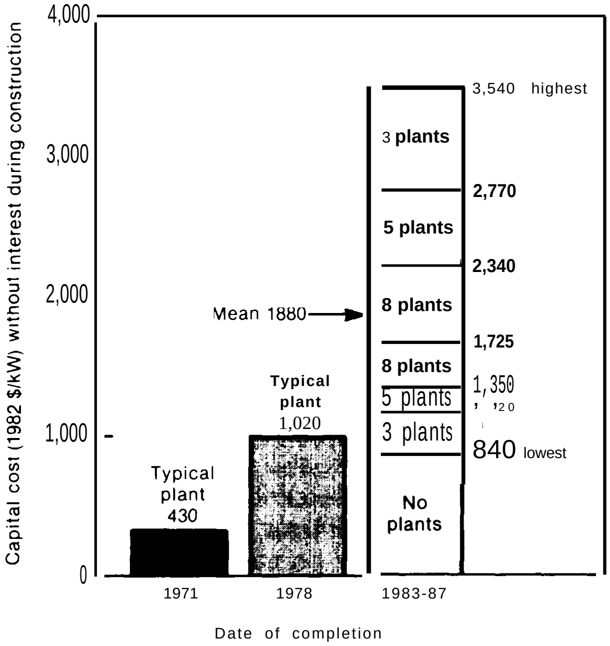
Figure 15.–Costs of Nuclear Units With Construction Permits Issued, 1966-71 (without interest during construction)



NOTE: Plant costs in mid-1979 dollars were escalated to mid-1962 dollars using the Handy-Whitman index for nuclear plant components (multiplying by a factor of 1.276).

SOURCE: Updated by OTA from data In Charles Komanoff, *Power Plant Cost Escalation,* Komanoff Energy Associates 1961, republished by Van Nostrand Reinhold, 1962.

Figure 16.—Total Capital Costs for Nuclear Plants Completed in 1971, 1978, and 1983=87 (estimated) in 1982 Dollars Without Interest During Construction



NOTES: “Plant” is defined as a single nuclear site or station with one or more reactors, The plant costs in-mid-1979 dollars from Komanoff’s book *for* 1971 and 1978 plants were stripped of interest and escalated to mid-1962 dollars using the Handy-Whitman index for nuclear plant components (multiplying by a factor of 1.276). The costs for the plants to be completed in 1963-87 are based on mid-1963 utility estimates for a group of 32 sites (stations) with a total of 50 reactors and excludes: Marble Hill, Waterford 3, Susquehanna and all Washington Public Power System (WPPS) plants except WPPS 2.

SOURCE: Charles Komanoff, *Power Plant Cost Escalation,* Komanoff Energy Associates, 1981, republished by Van Nostrand Reinhold 1982; unpublished analysis from forthcoming report by Charles Komanoff and Irving C. Bupp to be published in the winter of 1984, and the Off Ice of Technology Assessment.

constructed from a composite of characteristics associated with average and not high or low costs) with the full range of costs estimated for a group of 32 plants under construction for completion in the 1980’s. The cost (in 1982 dollars) of a typical plant increased from about $430/kW in 1971 to $1,020/kW in 1978, to a range of $840 to $3,540/kW for plants under construction in 1983. The median plant of this group is expected to cost $1,725/kW and the average cost is somewhat higher ($1,880/kW) reflecting the wide variation in costs at the upper end of this wide range.

The same increase also is evident in pairs of plants built by the same company and intended to be identical except for regulatory changes and some construction management improvements. The cost of Florida Power & Light’s St. Lucie 2 when completed in 1983 ($1,700/kW in 1982 dollars) was about 50 percent more than that of St. Lucie 1 completed in 1976. Commonwealth Edison’s Byron 1 and 2, to be completed in 1984 and 1985 at an estimated cost of $1,100 to $1,150/kW (in 1982 dollars) will cost about 90 percent more than the company’s Zion 1 and 2, completed in 1973 and 1974.

Until the early 1980’s, nuclear plant costs increased steadily with each generation of plants (55,61,75). However, Komanoff’s analysis shows no tendency for plants scheduled for completion later in the 1980’s to have significantly greater expected costs than plants being completed in 1983-84. In part, this may be due to underestimation of costs for plants still far from completion, but it also is probable that factors other than time now are more influential on powerplant cost. (A complete list of the mixed-dollar cost for plants in various stages of completion is given in app. table 3A.)

The variation from lowest to highest cost nuclear powerplants in the current generation is striking. Construction costs per kilowatt are expected to be over four times higher (in 1982 dollars) for Long Island Lighting Co.'s Shoreham at $3,500/kW than they are for Duke Power's McGuire 1 and 2 at $840/kW. For the current generation of plants, Komanoff found some variables that explain much of this large variation (56). For example, estimated plant cost decreases about 15 percent for every doubling of the number of megawatts at a single site. Estimated plant cost also decreases 8 to 10 percent for each previous plant site built by the same utility. Based on these results, a utility that had built on 5 previous plant sites should be able to construct its next plant site for 30 to 40 percent less than a utility with no experience. Plant cost also varies by manufacturer (as much as 15 percent) and is significantly higher (30 to 40 percent) for plants located in the Northeast region due primarily to higher labor cost and shorter construction seasons.

The importance of utility experience and site-related experience for this latest group of plants is evidence of the impact of some of the utility managerial experience described in chapter 5. There seems to be a site-specific and company-specific learning-curve for bringing plant costs down.

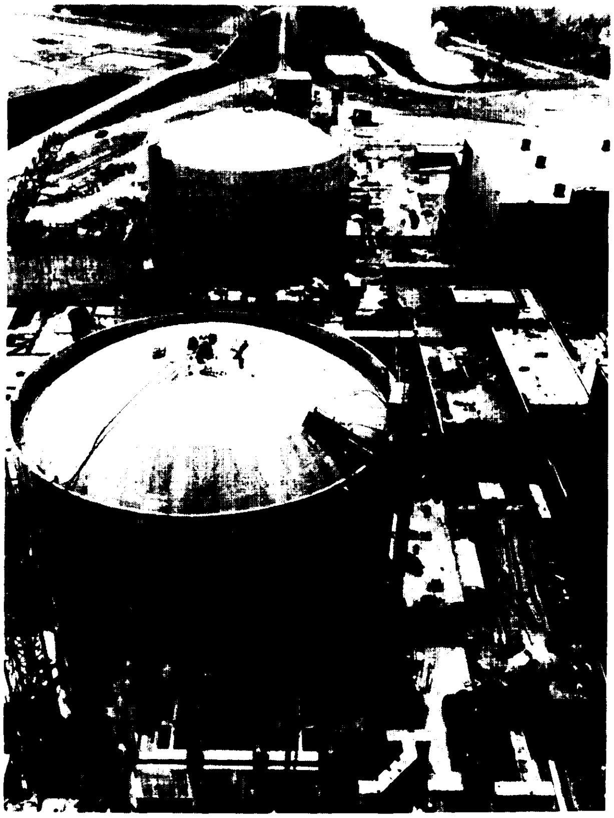


Photo credit: Duke Power Co.

Capital costs per kilowatt of identical plants at a single site are usually lower than average. This photo shows Catawba nuclear station, owned by Duke Power Co., which is expected to produce among the lowest cost electricity of any plant in its timeframe when it comes online in 1985

Reasons for Increased Construction Cost

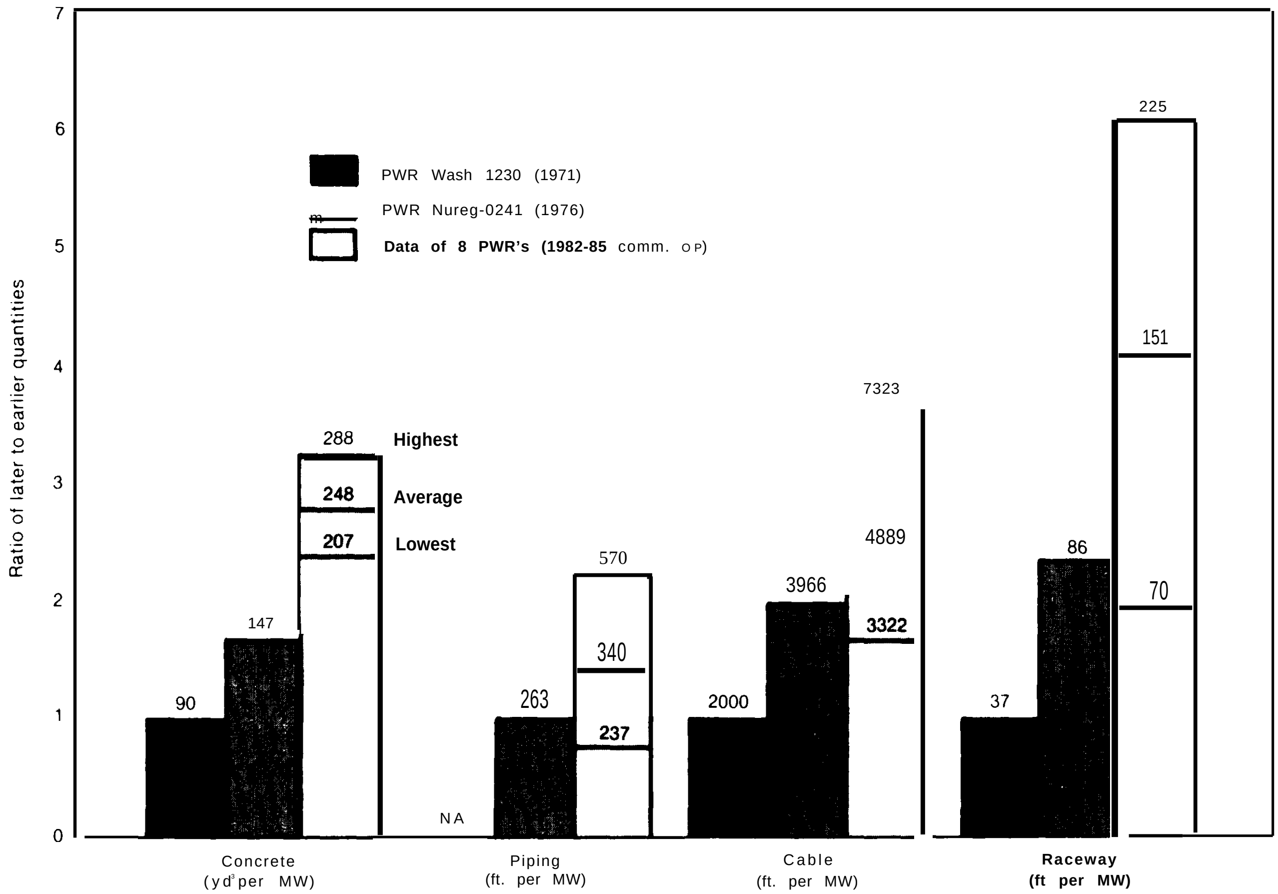
Several different kinds of increase contributed to the dramatic increase in average cost described above. To begin with, these comparative cost estimates exclude the influence of nuclear-component inflation that compares the cost of equal-quality nuclear components and materials over time. Nuclear component prices increased **1 or 2** percentage points faster than inflation. *

Several changes account for the increase in constant dollar cost. According to several related DOE studies, materials used in nuclear plants have increased, e.g., from an estimated 2,000 ft/MW of cable for a typical plant to be constructed in 1971 to about 5,000 ft/MW of cable for the average of eight plants under construction in 1982-85. Figure 17 shows similar increases in the use of concrete, piping and cable raceway (supports for electric cable) (1 **7).** Increased material requirements are due both to direct increases in structural and electrical complexity and to the increased rework necessary to meet more stringent quality-control requirements.

Materials also have become more complex. A whole set of seismic requirements to restrain piping systems during earthquakes was introduced in the late 1970's. **Simple cast or machined pipe supports (costing several hundred dollars) have been replaced with very sophisticated restraints called "snub bers," with shock-absorbers, costing many thousands of dollars. Pipe supports have become more massive and have had to be fitted**

***This is measured by the Handy-Whitman nuclear index (55).**

Figure 17.—Trends in Material Requirements in Estimates of PWR Construction Cost



NOTE The first two columns come from engineering estimates prepared for the NRC (formerly the AEC) based on construction data from plants under construction or complete at that time The last column comes from a survey of eight plants under construction See source article for references and more description

SOURCE John H. Crowley and Jerry D. Griffith, "'U S Construction Cost Rise Threatens Nuclear Option " Nuclear *Engineering International,* June 1982

with much tighter tolerances to the pipes they support.

Quality-control procedures and paperwork have added to the cost of materials and components. Although there has been no comprehensive study, there are individual examples and anecdotes to illustrate the claim that quality control represents a bigger and bigger share of nuclear materials cost. In one such example (86) structural steel supports now required for nuclear plants cost between two and three times the cost of the same quality steel supports that are still used for general construction projects and that were permitted on nuclear projects until 1975. Of this amount, the quality control procedures account for virtually all the increased cost.

Finally, there has been a steady increase in the amount of labor required per kW, both manual (craft) and nonmanual. For a series of typical plants costed out over 15 years in a study for DOE, craft labor requirements increased from 3.5 workhours/kW for **a** plant starting construction in 1967 to **21.6** workhours/kW for the average of 16 plants under construction for completion in 1982-85 (17). Nonmanual field and engineering services also have increased dramatically. For a slightly different series of typical plants, estimates of field and engineering services increased from 1.3 workhours/kW in 1967 to 9.2 workhours/kW in 1980 (16).

The increase in labor per kilowatt of capacity is the result of complex interactions resulting from increasingly demanding regulations, quality-assurance requirements and the subsequent utility management response to these. These are described in more detail in chapters 4 and 5 and in several case studies (92).

There is large variation in material and labor requirements from plant to plant, just as there is large variation in overall capital cost. For a group of 16 plants scheduled to be completed in 1982-86, craft labor varied from a low of 15 workhours/kW to a high of 33 workhours/kW. Similarly, for a group of eight plants, linear feet of cable varied from a low of about 3,300 ft/MW to a high of about 7,300 ft/MW (see fig. 17).

The Increase in Nuclear Construction Leadtimes

Nuclear construction leadtimes also increased over the decade, making it increasingly difficult to match nuclear plants to demand, adding to interest and escalation costs, and exacerbating problems with cash flow. At the same time, leadtimes for coal plants increased very little (from an average of 58 to about 60 months) (1).

Documenting the increase in leadtimes for nuclear plants is made difficult by the fact that some plants have been delayed deliberately by their

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utilities because of slow growth in electricity demand and financing difficulties. There also appears to be important differences in the regulatory environments for different generations of plants that must also be taken into account.

A recent study of leadtimes for EPRI took both deliberate delays and regulatory stage into account* (1). The study identified from published sources those plants that had been delayed deliberately more than a year by their utilities and analyzed their leadtimes in a separate group. In a more detailed case study of 26 of these plants EPRI found that 8 had been delayed significantly (averaging 27 months) while 22 had only been delayed an average of 2.5 months.

Grouped by date of permit, it is plausible to identify three generations of nuclear plants. For the first generation, for which construction permits were issued from 1966 to 1971, leadtimes* * increased steadily from about 60 to 80 months. This appears to reflect an increase in the designed complexity of nuclear powerplants and possibly the strains of rapid growth as well.

A second group of plants had their construction permits issued from **1971** to **1974.** Leadtimes for that group were much higher than the first, averaging 120 months and ranging from 100 to 160 months. Leadtimes for plants without significant deliberate delays averaged about 10 months less than those with significant deliberate delays. It appears that this group of plants suffered a major increase in regulatory complexity (including the 1974 Calvert Cliffs decision, the regulations following the 1976 Browns Ferry fire and the 1979 accident at Three Mile Island) without the opportunity to develop construction and regulatory planning techniques to handle the increased complexity. They may have suffered as well from some of the effects of rapid growth in the industry, such as incomplete designs and inexperienced supervisors.

Although the data are sketchy, it is possible that a third generation of nuclear plants is now emerg-

***The study grouped the plants by date of construction permit to avoid the obvious problem that later completion dates, by definition, include a larger proportion of long-leadtime plants.**

*** *Leadtimes for this analysis are defined as time from date of construction permit to commercial operation.**

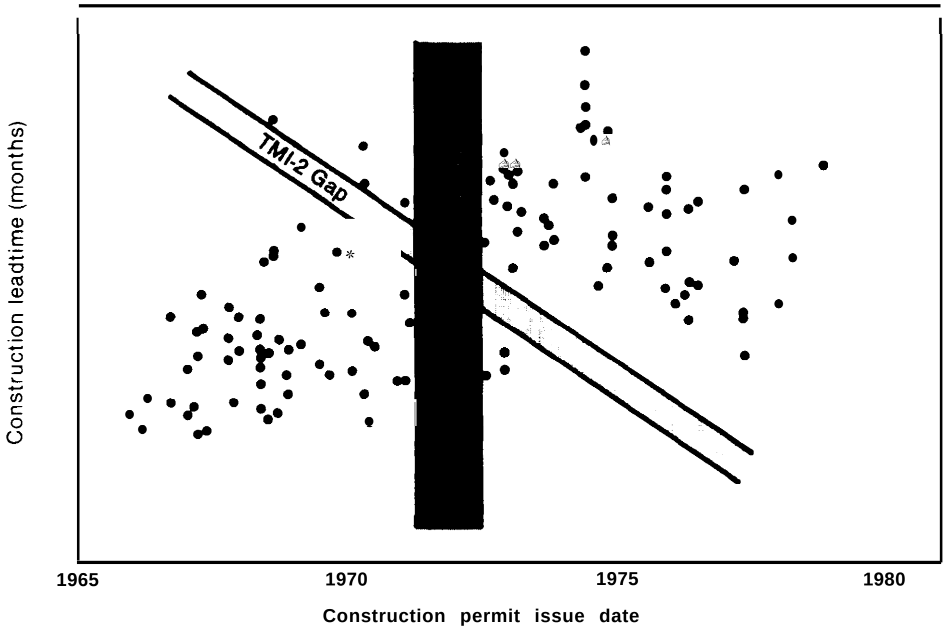
ing, with construction permits issued later, in 1975-77. After adjusting for deliberate delays and excess optimism in time estimates, EPRI found that this latest group of plants appears to have somewhat shorter leadtimes than the 1971-74 group. Leadtimes for all plants in the group average about 100 months and range from 65 to 120 months. Plants without significant announced deliberate delays average 10 to 15 months less than the average. The plants with shortest leadtimes in this group are already in operation and were completed faster than the shortest leadtime plants in the earlier group (see fig. 18). The numbers are so small, however, that it is too early to tell if these plants are anything but anomalies. Those plants with longer leadtimes in this latest group still may experience significant delays beyond the adjusted estimates calculated by EPRI. At the same time there is some case study evidence that the plants that were started later were able to compensate for increased regulatory complexity in the plant design and construction management and were also able to plan systematically their dealings with the NRC. (Case Study 2 in ch. 6.)

The Impact of Delay on Cost

In a period of substantial general inflation characteristic of the last 5 years, a delay in nuclear plant construction can cause an alarming increase in the current dollar cost of the plant. Increases in the current dollar cost, however, must be distinguished carefully from increases in the real or constant dollar cost of the plant (after the impact of general inflation has been eliminated). These in turn must be distinguished from increases due to changes in regulations or other external influence during the period of delay.

For a hypothetical plant that has been expected to be completed in 8 years but instead has been delayed to 12 years, with no increase in complexity or scope, there are two sources of increases **in total capital cost in constant dollars. One is that nuclear components, materials and labor may**

Figure 18.—Construction Leadtimes for Nuclear Powerplants



NOTES. The leadtimes are based on estimated times to commercial operation for those plants not yet in service. The gaps correspond to periods of licensing inactivity in the industry Leadtimes are calculated from construction permit issue date-to-date of commercial operation

SOURCE Applied Decision Analysis, Inc *An Analysis of Power Plant Construction Lead Times, Volume 1: Analysis and Results,* EPRI-EA-2880 February 1983 Graph based on Nuclear Regulatory Commission data.

have increased 1 or 2 percent faster than general inflation (escalation). The second is real interest during construction* that is capitalized and added to general total plant cost as AFUDC (Allowance for Funds Used During Construction). (See box B above.)

Table 9 shows the increases in constant dollars and in current dollars of several different cases: 5, 7, and 9 percent general inflation with no real escalation in nuclear components and with 2 percent real escalation and real interest rates of 3 percent and 5 percent above general inflation (1 3). Several of the examples in table 9 can serve as illustrations of the difference between increases in current and constant dollars. For example, in case 3, if a plant takes 12 years to build during a period of general inflation of 7 percent, escalation of nuclear components of 9 percent (2 percentage points faster than general inflation) and an interest rate of 12 percent (a rather high real interest rate of 5 percent), the "mixed current dollar cost" of the plant will be 233 percent higher than its overnight construction cost. Two-thirds of the increase, however, is general inflation. The real constant dollar increase in the plant cost is only 48 percent. Construction of the same plant in *8* years time would cause a current dollar increase of only 123 percent and a constant dollar increase of 30 percent. For this case, shortening the plant's leadtime would save about a third of its current dollar cost but only about 12 percent of its constant dollar cost. *

*Real interest is the nominal rate of interest less the rate of general inflation, e.g., real interest is 5 percent for nominal interest rates of 12 percent when general inflation is 7 percent.

*In this case 2.23 (8 years) is about 67 percent of 3.33 (12 years) and 1.30 (8 years) is about 88 percent of 1.48 (12 years).

The Cost of Electricity From Coal and Nuclear Plants

The steadily increasing capital costs of nuclear power (including the increasing costs brought about by increasing leadtimes) leads to a crucial question: at what point does the increasing capital cost of nuclear plants make nuclear power a more expensive source of electricity compared to alternative generating sources, especially coal? As long as it is likely that utilities will avoid the use of oil and gas for base load electricity generation, the chief competitor to nuclear is coal.

Initially (for most nuclear plants completed by the early or mid-1970's) there was no doubt that electricity generated from these plants was substantially cheaper than coal-generated electricity. Because of the way capital charges are recovered in the rate base (see box **C** above), the cost of electricity from these plants has become steadily cheaper relative to electricity from coal plants built at the same time. As the capital cost of nuclear plants has risen, however, the relative ad-

Table 9.—Additions to Overnight Construction Cost Due to Inflation, Escalation and Interest During Construction (in constant and current dollars)

	Percent increase in constant dollars		Percent increase in current dollars	
	8-year leadtime	12-year leadtime	8-year leadtime	12-year leadtime
Case 1: 7% general inflation, 0 escalation, 100/0 interest rate	+ 12	+ 19	+92	+ 167
Case 2: 7% general inflation, 0 escalation, 12% interest rate	+21	+33	+ 107	+ 200
Case 3: 7% inflation, 2% escalation, 12% interest rate	+30	+48	+ 123	+ 233
Case 4: 5% inflation, O escalation, 100/0 interest rate	—	+34	—	+ 140
Case *5:* 90/0 inflation, O escalation, 14% interest rate	—	+33	—	+ 273

NOTE: "Escalation" is defined as the increase in the unit costs of labor and components used in nuclear plants (with no change in quality) above the rate of general inflation. For inflation of 7 percent, an interest rate of 10 percent corresponds to a real interest rate of 3 percent, an interest rate of 12 percent corresponds to a real interest rate of 5 percent.

SOURCE: For the calculation, Wilfred H. Comtois, "Escalation Interest During Construction and Power Plant Schedules," Westinghouse Power Systems Marketing, September 1975.

vantage of nuclear power has diminished. For plants presently under construction, the average capital cost is now so high that the typical nuclear plant probably would produce more expensive electricity over its life time than the typical coal plant. Only electricity from the least expensive nuclear plants still may be competitive with average cost coal-generated electricity. Average cost nuclear plants, however, still can compete with more expensive coal plants.

Comparing the costs of nuclear and coal-fired electricity is made difficult by the different impact of fuel and capital cost components for each type of plant. Capital cost is a far more important component of nuclear-generated electricity than for coal plants. While the levelized cost of fuel (uranium ore, enrichment, storage shipment and disposal) and operations and maintenance each run about $0.0075/kWh, the capital charge (levelized charge* over the life of the plant) per kWh for new plants may range from as little as $0.01/kWh for older reactors to $0.10/kWh or even more for the most expensive of today's reactors. The capital charge per kWh increases with higher total construction cost (including the impact of longer leadtimes), with higher interest rates, and with a shorter capital recovery period. The capital charge (as well as operations and maintenance) per kWh also increases as the plant capacity factor** is reduced because there is less output among which to apportion the annual capital cost. Since the earliest nuclear plants were built, there have been significant increases in all the categories that increase annual capital charges. The capacity factors of nuclear plants also have been less than expected. (See ch. 5 for more discussion of nuclear capacity factors.)

For coal-fired electricity, on the other hand, the cost of the fuel is at least as important as the capital cost in determining the price of electricity over the life of the plant. Operations and maintenance of coal plants cost somewhat less than for nuclear plants. Fuel cost, however, may range from less than $0.01/kWh in regions where plants can be built near the coal mine to almost four times that in regions located far from coal fields (assuming rapid increases in coal prices). The rate at which coal prices are likely to escalate over several decades has a significant influence on the forecast average cost of electricity from the plant over its lifetime. Levelized electricity prices will be about $0.015/kWh (in constant dollars), higher, on average, if coal prices escalate at a real annual rate of 4 percent than if they don't escalate at all in real terms (36).

Unfortunately, there is no study of recent plants using actual reported capital cost of coal plants. In a DOE study (36) using coal and nuclear plant model data on capital cost, the cost of electricity is about equal in five of the ten DOE regions, slightly lower for nuclear in two of the regions and considerably lower for coal in two of the regions. **There is reason to believe, however that nuclear capital costs are higher and coal capital costs may be lower than the study results.** Capital costs of the typical nuclear plant reported in the study are about 15 percent lower than the average (in constant dollars) of the plants now under construction. On the other hand, the capital cost of the typical coal plant reported in the DOE study is more than 40 percent higher than the capital cost of the typical 1978 coal plant (including a flue-gas desulphurization scrubber) in the 1981 Komanoff study updated to constant 1982 dollars. While it is possible that the capital cost of coal plants may have increased 40 percent since 1978, several factors make it unlikely. Coal plant construction leadtimes (unlike nuclear plant leadtimes) have not increased since 1978. Since the cost of scrubbers already is included in the 1978 typical coal plant capital cost, it is unlikely that further pollution control improvements and design improvements would add more than 20 percent. If, indeed, actual nuclear construction costs are higher and actual coal plant construction costs are lower than the plant model results, the typical nuclear plant would be expected to produce more expensive electricity in all regions.

Low-cost nuclear plants, however, still would be competitive with the average coal plant. Com-

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***Various techniques are used to "levelize" costs over a plant's lifetime. One simple method,** used **in the EIA study of coal and nuclear costs, is to take the present discounted value of the stream of costs and divide it by the number of years to get an annual levelized cost (36).**

****Capacity factor equals the number of hours of actual operation divided by the hours in the year.**

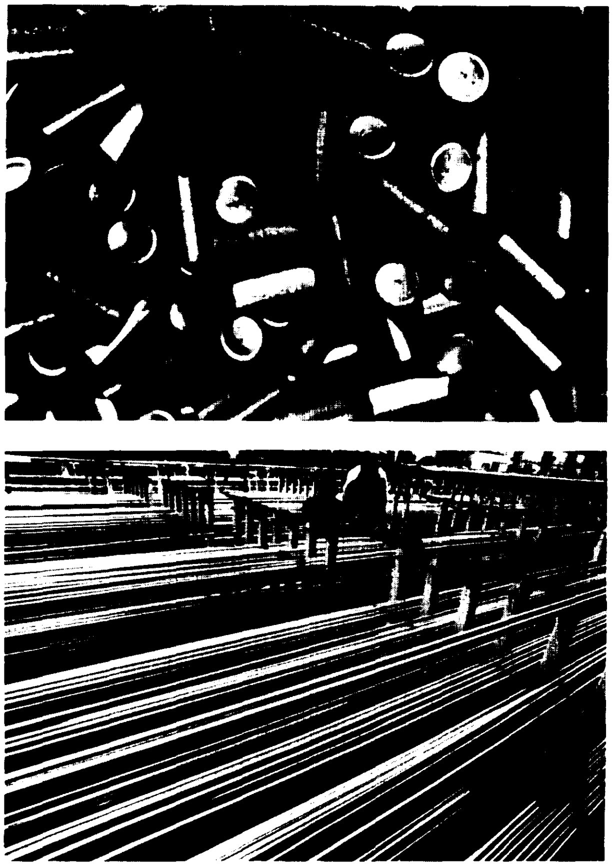

Photo credits: Atomic Industrial Forum

Nuclear fuel comes in pellets and is assembled into fuel rods and then into fuel assemblies. Fuel for a nuclear powerplant is compact and only transported every 12 to 18 months. It is inexpensive compared to the cost of alternative fuels such **as coal, natural gas, and oil. Each Vi-inch-long pellet of enriched uranium shown** here can generate approximately the same amount of electricity as 1 ton of coal

monwealth Edison Byron plants are expected to cost $1,100 to $1, 150/kW in 1982 dollars (without interest during construction)* and Duke Power's McGuire and Catawba plants are expected to cost $900 to $1,200/kW in 1982 dollars. When the construction cost of a nuclear plant is no more than 20 to 40 percent above that of a coal plant, it can be expected to produce electricity more cheaply, sometimes substantially, over the plant's lifetime.

However, there is a further element of the competition between the costs of electricity from nuclear and from coal. The pattern of costs over the life of the plants are substantially different. Under current accounting rules capital charges are highest in the early years and decrease as depreciation charges are deducted from the asset base. Coal costs on the other hand will increase at, or faster than, the rate of general inflation over the life of the plant. Thus for plants with the same levelized cost of electricity, electricity from the nuclear plant will cost more in the early years and electricity from the coal plant will cost more in later years (see box C above). The higher cost of nuclear plants in the early years could be discouraging to an electric utility that had faced much opposition to rate increases.

Future Construction Costs of Nuclear Powerplants

It is very unlikely that there will be any future for nuclear plants of current average capital cost. Nuclear plants, on average, are now so costly that they are no longer likely to produce electricity more cheaply than coal over their lifetimes. Given the pattern of front-end loading of capital costs, even with equal lifetime costs, nuclear-generated electricity would not be cheaper than coal-generated electricity for 10 to 15 years. For this reason, utilities are not likely to order more nuclear plants if the capital cost of newly ordered plants is expected to repeat that of the current average plant.

There is considerable evidence that, with effort, the cost of an average nuclear plant can be reduced substantially from the current level. The lowest cost nuclear plants already cost substantially less than the average. Within the present framework of regulatory requirements for plant design and quality control, a few utilities have built enough plants to take advantage of a construction learning curve and have developed techniques for minimizing delays, rework, and worker idleness. These techniques are described in more detail in chapter 5. They involve careful and complete engineering, careful and thorough planning and project management (including the use of sophisticated computerized tracking and

*Costs of the **Byron plants may go up, however, following a January 1984 NRC decision to deny the plants an operating license.**

inventory planning), and attention to motivation for productivity and cooperation. If a separate company is used to manage the project, there must be explicit incentives to complete projects on time and at budgeted cost. A reasonable goal for such efforts could be to equal the capital cost of Commonwealth Edison's Byron and Braidwood plants and Duke Power's McGuire/Catawba plants of $1,100/kW (1982 dollars) direct construction cost plus another $200 to $250/kW for interest during construction.

Looking overseas, there is evidence that a different approach to certain aspects of safety regulation and quality control could bring construction costs down still further. Constructing a French plant requires about half as many workhours/kW as constructing an American plant (86). As is described in more detail in chapter 7, the French have standardized their plants and have built two basic types of reactors (925 MW and 1,300 MW). **This avoids much of the rework that** occurs in American plants because the engineering is essentially complete before each plant is started, and because the first plant of each type functions as a full-scale model to help avoid piping and cable interferences and other problems of two dimensional design. Within a far more centralized and controlled approach to safety regulation (see ch. 7) the French have also taken an approach to earthquake protection that minimizes the impact on construction. They also have a different approach to quality control that minimizes delays during construction (described in chs. 4 and 5).

A specific estimate of possible reductions in average plant cost was made in a recent study of the U.S. nuclear industry viability (87). According to this estimate, typical plant costs (including interest during construction) could be reduced from about $2,220/kW (in 1982 dollars) to $1,700 to $1,800/kW (20 to 25 percent less). This estimate assumes that the United States can go only part way towards constructing plants with as few workhours as is now done in France. The French regulatory environment, and utility management, and construction tradition are sufficiently different that much is unlikely to be duplicated in the United States. The proposed steps to bring construction costs down would include:

- **Reduction in Construction Workhours.** A fully standardized pre-certified design and emphasis on multi-unit sites could reduce construction workhours from 14 million to 12 million per 1,300-MW plant, a number which is still about 25 percent higher than estimated construction workhours for a comparable French plant. This would come about through progress up a learning curve of construction management techniques.
- Reduction **in Engineering Workhours.** Standardization and regulatory predictability also could cut engineering workhours per plant roughly in half from about 9 million to about 4.5 million, by reducing construction engineering support by more than 80 percent and quality assurance workhours similarly. Engineering workhours would still be about 60 percent higher than those in France, reflecting the differences in U.S. construction project organization.
- **Eight-Year Project Schedule.** Reducing average project schedules from 11 to 8 years would reduce interest and real escalation costs. Total construction cost in constant dollars would be reduced by 7 to 15 percent (see table 9).

The desirability of standardization in nuclear plant design and construction is a complex question that would affect far more than the capital cost of nuclear plants. It was the subject of a previous OTA report, *Nuclear Powerplant Standardization* (April 1981) and is discussed further in chapter 4. One issue is whether standardization can be achieved without sacrificing the adaptability of nuclear technology to new information about designs that would benefit nuclear plant safety or operation. A second issue is the institutional obstacles to standardization in an industry with more than 60 nuclear utilities, 4 reactor vendors, and more than 10 AE firms.

While opportunities exist for reducing nuclear construction costs, it should be recognized that costs might also increase. Further serious accidents could lead to a new round of major changes **in regulation. There are still important unresolved safety issues (discussed in ch. 4) that could lead to costly new regulations. utility executives are well aware of this possibility.**

The Financial Risk of Operating a Nuclear Powerplant

The Risk of Property Damage.–The accident at Three Mile Island was a watershed in U.S. nuclear power history because it proved that serious accidents could indeed occur and cause enormous property losses even without causing any offsite damage. The total cost of the cleanup is estimated at $1 billion, not counting the carrying costs and amortization of the original capital used in building the plant nor the cost of restarting the plant. Of this $1 billion, $300 million was covered by insurance from the insurance pool (see table 10 for explanations). General public Utilities (GPU) is now in the process of negotiating the financing of the rest from various sources including the utility industry through the Edison Electric Institute, the rate payers as approved by the Pennsylvania and New Jersey PUCs, the States of Pennsylvania and New Jersey and the Federal Government.

Since Three Mile Island, property insurance coverage for nuclear plants has increased to $1 billion, about half in primary insurance and the rest in excess insurance (once a **$500 million accident** cost has been reached). Some of the primary insurance and most of the excess insurance have been provided by two new mutual insurance companies formed by groups of utilities, Nuclear Mutual Ltd. (NML) and Nuclear Electric Insurance Ltd. (NEIL) –(see table 10). NEIL also provides almost $200 million in insurance for purchases of replacement power while a plant is disabled.

Despite this threefold increase in insurance, however, some of the expenses incurred in the Three Mile Island accident still have not been insured; namely, maintenance of the disabled plant and carrying costs and amortization of the capital tied up in the disabled plant. For the moment these are being paid by GPU stockholders who have not received a dividend since the accident (44).

Table 10.—Nuclear Plant Property and Liability Insurance

Description	Coverage
ANI-MAERP:	
Commercial insurance consortium of about 140 investor-owned companies (American Nuclear Insurers - ANI) and 120 mutual companies (Mutual Atomic Energy Reinsurance Pool — MAERP)	Reactors at 34 sites. "Primary" insurance (responds initially to a loss) $500 million/site $68 million excess
NML:	
Nuclear Mutual Limited is a mutual insurance company created by several investor-owned utilities and located in Bermuda	Reactors at 27 sites, $500 million primary insurance/site
NEIL-I:	
Nuclear Electric Insurance Limited — extra expense insurance to pay for replacement power from an accident covered in primary insurance	Reactors at 36 sites, $2.3 million/ week 1st year; $1.15 million/week 2nd year up to $195 million
NEIL-II:	
Nuclear Electric Insurance Limited — property damage excess damage above limit of primary insurance	Reactors at 32 sites. "Excess" insurance (covers damage above limit of primary insurance) $415 million/site
Liability *insurance:*	
ANI-MAERP:	
Liability insurance required by Price-Anderson	All reactors. $160 million available from premiums, plus $400 million/ accident available from retroactive assessments of $5 million/reactor/ accident

SOURCE: **John D. Long, Nuclear** *Property Insurance: Status and Outlook,* **report for the U.S. Nuclear Regulatory Commission, NUREG-0891, May 1982; papers presented at Atomic Industrial Forum Conference on Nuclear Insurance, Feb. 14-16, 1983.**

Further increases in insurance capacity are desirable, given the increasing replacement value of plants. However, they are limited by the assets of the insurance companies and the utilities in this country and by the reluctance of reinsurers, such as individual syndicators in Lloyd's of London, to assume any more American nuclear risk.

The adequacy of current insurance is threatened further by several other issues. Under public pressure, Congress could stipulate that all property insurance be used first to pay cleanup costs and only then to pay carrying costs and the costs of restarting the plant. This would mean that the utility would have to turn to the PUC to obtain higher electricity rates to cover all the other costs of an accident or obtain the funds by withholding dividends from shareholders. Another source of uncertainty is the heavy reliance of the utility-run mutual insurance systems on retroactive assessments. These are premiums that the utility commits itself to pay in the event of an accident. NML, for example, may call on retroactive payments up to 14 times annual premiums in the event of a serious accident that depletes existing insurance reserves. The willingness and ability of utilities to pay these assessments has not yet been tested. Some observers have expressed the fear that PUCs may balk at allowing utility insurance expenses "to pay for the other guy's accident" (57).

The Risk of public Liability .–Since 1957, the Price-Anderson Act has limited public liability, in the event of a serious accident, to $560 million. Pressure to increase this limit has been mounting. Inflation alone would justify raising the limit to about $1.9 billion assuming $560 million was an appropriate figure in 1957. Pressure, however, to go beyond keeping up with inflation, or even to eliminate the limit altogether, arises from several studies published over the last 10 years, the Rasmussen Report (WASH-1900) in 1974 and the 1982 Sandia siting study. Both analyze the consequences from low probability accidents and are described more fully in chapter 8. Part of the Price-Anderson Act is due to expire in 1987. The first round of debate in Congress on this issue may begin soon, stimulated by the recent publication of an NRC report on public liability.

Ironically, this pressure to increase the limit for public liability comes just as the private insurance resources of the industry have increased enough to *cover* the current statutory limit fully. About $160 million is available from the insurance pools, and the rest (about $400 million) is available from a $5 million per reactor retroactive assessment required in the Price-Anderson Act. Under current law, the Federal Government has guaranteed to provide any liability damages beyond the nuclear industry's resources and up to the statutory limit. Currently, because of the availability of private insurance funds and the increase in the number of plants available to pay the $5 million assessment, the Federal Government has no liability. if the limit were raised or eliminated, there would be pressure for the Federal Government to again assume the excess liability.

From the standpoint of the insurance industry, the most serious issue is the growing pressure from citizen's groups to allow damage from nuclear accidents to be covered in homeowners' policies. Currently, by consensus of all insurers, all homeowners' insurance policies specifically exclude a nuclear accident as an insurable risk. Homeowners, in effect, may make claims only against the responsible utility and be paid from the utility's *own* insurance resources. For insurers, this characteristic of nuclear insurance channels the risk into a single category which can be identified and assessed. Since the potential damages are both large and of unknown probability, insurers are much more willing to provide fairly large sums if the structure of risk is simple because a given accident will result only in a claim from a single utility, and not in hundreds of individual homeowner claims through multiple insurance companies. Were the homeowner's insurance exclusion to be removed by law, one probable result would be a reduction in total private insurance resources available for a single accident. This is because the resulting multiple sources of liability (from millions of homeowner policies) increases the perceived risk to the insurers, who in turn respond by reducing the total amount available.

Another financial risk of unknown size is the possibility that workers exposed to radiation may file occupational health suits in future years, based on a statistical link between low-level radiation exposures and various diseases, such as cancer, with long periods of development. In some respects the nuclear power industry is better prepared for such suits than industry has been for comparable suits arising from exposure to asbestos because detailed records are kept on every worker's exposure to radiation. Currently, any court settlements due to workers' exposure to radiation would be paid out of ANI-MAERP pool insurance. If the size of such settlements becomes at all substantial, however, utilities and their insurers may move to establish a fixed compensation program, comparable to the basic workman's compensation program, which pays fixed sums for each type of injury. Since injury in this case is based on a probability link to levels of radiation exposure the level of probability would be included in the program, much as has been proposed for compensation for victims of nuclear weapons testing.

Photo credit: Westinghouse

One source of uncertainty about the future cost of nuclear power is the possibility that workers exposed to radiation may sue the nuclear plant owners to recover damages from health effects of radiation exposure

Impact of Risk on the Cost of Capital

As previously noted, from an investor's point of view there are several reasons to be wary of utilities with substantial nuclear operations:

- since nuclear-generating plants take longer to build, it is more likely that they will be poorly matched to actual demand;
- the cost of constructing them is harder to estimate and control than it is for coal plants; and
- there is a small but finite risk of a major disabling accident. Under current insurance coverage and PUC rate decisions, a large fraction of the many costs of such an accident would have to be borne by the stockholder.

A few attempts have been made to estimate the impact of these three elements of risk on the cost of capital to nuclear-owning utilities but the results are not clear-cut. As of 1981, the highest bond ratings belonged to utilities operating nuclear plants, although the lowest bond ratings belonged to utilities with nuclear plants under construction. After Three Mile Island, there was an immediate effect on the relative stock market prices of nuclear and non-nuclear utility stocks. The price of non-nuclear stock increased over 50 cents a share relative to nuclear stock. The effect persisted for at least 2 years (46). Financial experts and utility executives agree, however, that another serious accident could have very serious financial consequences.

In the year following the Three Mile Island incident, a study of investor attitudes towards nuclear utilities (1 1,46) showed that investors ranked the risks associated with nuclear power as a serious problem but less than problems caused by regulation, high interest rates and inflation. Twenty-five percent of institutional investors said the Three Mile Island accident had a negative impact on the weighting of electric utilities

in their investment portfolios. I n general, portfolio managers showed increased concern if utilities had a high dependence *on* nuclear, but over 82 percent said they recommend companies with some nuclear component in their fuel mix. It would seem that investors are more concerned currently about the risk of construction cost overruns and delays and the financial strains of plant construction than they are about the financial risk of a disabling accident (47). The recent indications that several nuclear plants such as Zimmer, Midlands, and Marble Hill may never be completed and licensed to operate has caused another round of investor concern. * Between October and late November 1983, stock prices dropped in 36 out of 50 companies with nuclear plants under construction.

In summary, utilities assume greater risks when they build nuclear plants than when they build coal plants. Even if, due to standardization and careful construction, the cost of nuclear power over 30 years is estimated to be substantially less than coal-fired electricity, utilities still might hesitate to order more nuclear plants unless they are compensated in some way for the additional risks.

*See *Nuclear phobia,* **a research report by Merrill Lynch, Pierce, Fenner & Smith, Dec. 15, 1983.**

NUCLEAR POWER IN THE CONTEXT OF UTILITY STRATEGIES

The decision to order a nuclear powerplant is only one of many choices utility executives can make given their companies' load forecasts and present and future financial situations. They could instead order one or more coal plants; convert an oil or gas plant to coal; build a transmission line to facilitate purchase of bulk power from Canada or from elsewhere in the United States; develop small hydroelectric sources, wind sources, or other small-scale sources of power; or start a load-management, cogeneration, or energy conservation program (or some combination of all of these).

What utility executives choose depends on the reliability of their load forecasts, the options for retiring oil and natural gas plants, the availability of reliable sources of purchased power, the nature of rate regulation in the State in which they operate, and their companies' abilities to manage large construction projects on the one hand or successful load management and conservation programs on the other.

From a recent survey of utility executives (90) and the results of two OTA workshops, it is clear that utility executives are now considering a much wider variety of alternatives to construction of new large generating plants. Although utilities do not seem to be avoiding capital investment at the risk of providing inadequate electric supplies, nonetheless they are taking financial considerations heavily into account, especially the ability to earn a return on CWIP. Some executives say their companies have deliberate policies of providing generating capacity with either minimum capital cost or short leadtimes or both.

One possible option is to delay any powerplant construction as long as possible and then meet any need for new capacity with combustion turbines which can be constructed in 3 to 4 years and cost only $200 to $300/kW (in 1982 dollars). Such a choice is now less risky for future electricity rates because of apparent softening of natural gas markets. Combustion turbines cost so little that they could in theory be written off quickly and replaced by longer leadtime plants if electricity demand were increasing enough to warrant longer leadtime generating capacity with lower fuel costs.

In a recent study six utilities described two alternative sets of construction plans: one plan that they would follow under financially generous rate regulation and the other under financially constrained rate regulation (64). There is a somewhat exaggerated difference between the two sets of circumstances*–but they do illustrate the range of utility choice.

Under financially constrained circumstances, the six utilities expect to rely on more use of purchased power. One will invest in more transmission lines. The utilities also expect to keep old plants on line and will defer the retiring of oil and natural gas plants. It is interesting that none expect to build combustion turbines to catch up to demand growth.**

The preferred generating choice of the six utilities under financially generous circumstances is medium-sized coal units of **500 to 600** MW which the six utilities plan to build in substantial numbers, over 17 GW by the year 2000. Although several utilities expect to finish nuclear powerplants under construction, only one of the six expects to start a new nuclear plant. Utility executives at the OTA workshops and in the survey now perceive nuclear power to be too risky to include in future construction projects even under a less financially constrained future. Even for those utilities that have experience in keeping construction costs under control, there are important perceived risks from lack of public acceptance and the possibility of one or more Three Mile Island types of accidents. Utility executives said they expect to make use of "cookie-cutter" coal plants because of the greater predictability of their operating and construction costs.

It is conceivable that other types of nuclear plants than those currently available in the United States would be more attractive to utility executives, Executives reported in an EPRI survey of utility executives' attitudes towards nuclear power that smaller nuclear plants would be desirable because they would require a smaller total capital commitment and could more easily be fit to uncertain load growth (22).

Some executives also believe that significant safety improvements would make nuclear plants less vulnerable to changes in regulation and adverse public reactions and thus more attractive. Several utilities are members of a gas-cooled reactor council that supports research and development of high temperature gas-cooled reactors (HTGR) (described inch. 4). One executive testified for Florida Power & Light Co. (FP&L) in March 1983 that for FP&L's crowded site in Dade County, an HTGR is the only option. Shallow water and delicate ecology hinder coal transportation and the closeness of the City of Miami and problems with raising the water temperature rule out a light water reactor. FP&L does not want all the possible headaches of building the lead HTGR but might be willing to build the second plant (91).

If utilities wish to avoid building powerplants altogether they have several options (14). One of these, featured in several of the six utility strategies described in table 11, is to make better use of existing powerplants. Ironically, the financial weakness and excess capacity that had led utilities to cancel new construction has also fostered neglect of maintenance of existing powerplants. In one recent survey of 80 GW of coal powerplants there had been a decline of more than 12 percent in availability from 1970 to 1981 (1 5). Pennsylvania is one of several States investigating changes in regulatory policies that would encourage more efficient use of existing powerplants **(78).**

Major investment may be needed to extend the life of an existing plant well beyond the normal retirement **age of 30 to 35** years. A **plant that** has **been operating** effectively for 40 to 50 years may not have any of the same components as the original plant. Nonetheless, substantial investment to upgrade an existing plant will in almost all cases cost far less than building an entirely new plant of the same capacity.

Utilities can also substitute programs to reduce peak demand for building new capacity. A recent EPRI survey identified over 200 utilities that were working with their customers on conservation and load management programs (23). While some of the programs were demonstrations, others represented major corporate commitments to load control. For example, the New England Electric System's successful experiments with on-

***For example, the cost of capital is assumed to differ by 300 basis points between the generously treated case which results in an AAA bond rating and the constrained case which results in a BBB bond rating.**

**** Building a combustion turbine for use more than 1,500 hours a year is still prohibited under the Fuel Use Act. In practice, however, an increasing number of exemptions are being allowed.**

Table 11.—Six Sets of Alternative Utility Construction Plans

Utility and type (timeframe of plan)	Projected growth in load (%/yr.)	Plan A capital discouraging	Plan B capital attraction
Utility A. Coal conversion (1982-2000)	1.5	Cost $4.1 billion • Sell part of share of nuclear plant • Convert 200 MW oil to coal • Reduce sales to outside customers • Purchase 175MW • Retire no old plants	Cost $9.9 billion • Finish nuclear plant on schedule • Convert oil plant to coal (800 MW) • Build four 600 MW coal plants (two-thirds ownership)
Utility B. Coal/nuclear (1982-2005)	2.0	Cost $23.9 billion • Delay two-thirds of a new nuclear plant for 4 years • Double the amount of purchased power • Consume more oil and gas • No existing plants retired	Cost $40.6 billion • Complete several nuclear plants without delay • Build four 500 MW coal plants in 1990's • 75 % share in two 1,100 MW nuclear units in 2000 • All plants retired on schedule • Intermediate load coal plant
Utility C. Gas/coal (1982-2000)	4.0	Cost $64.8 billion • 3,000 MW coal capacity 1982-97 • 6,000 MW coal capacity 1998-2009 • Reserve margins 13% 1990; 9.6% in 2000	Cost $62.8 billion • 5,000 MW new coal capacity in 600 MW increments 1982-97 • 5,000 MW more coal 1998-2009 • Reserve margin over 20%
Utility D. Gas displacement (1982-2001)	3.0	Cost $8.9 billion • Finish large nuclear plants near completion • No plants retired • Meet incremental demand through purchased power	Cost $30.5 billion • 2,500 MW of coal capacity 1988-97 to displace gas • Three large coal plants in mid-1990's to meet additional load • Oil and gas capacity retired on schedule • Finish large nuclear plants near completion
Utility E. Oil displacement (1982-2000)	1.5	Cost $12.9 billion • No construction projects • Defer 2,000 MW of natural gas and oil capacity	Cost $22.1 billion • Purchase share in large coal project under construction • Joint owner of coal plant online early 1990's • Build transmission lines to purchase power
Utility F. Purchase/coal (1982-2001)	3.0	Cost $4.8 billion • No construction • Increase purchased power to 36% of total • Spend $1 billion on transmission lines to wheel in power	Cost $7.6 billion • Four new coal units of 500 MW 1988-97 • Purchased power shrinks to 7 % of total capacity

SOURCE Peter Navarro. Long Term Impacts of Electricity Rate *Regulatory Policies* for DOE Electricity Policy Project, February 1983

site thermal storage of electric heat and home energy conservation led it to develop a 15-year plan aimed at reducing peak demand by over 500 MW and average demand by another 300 MW over the 1980-95 period. The plan is expected to save utility customers about $1.2 billion over that period (65).

Utilities have successfully used a wide variety of techniques to encourage investment in load management and energy conservation by their customers. As described in the EPRI report and others (14,23,42), these include programs to provide rebates for the purchase of energy-efficient refrigerators, air-conditioners, or heat pumps, low interest or interest-free loans and energy indexing programs. For a utility interested in conserving capital, some utility-controlled load management technologies offer strikingly low capital cost ($110 to $200/kW). It takes thousands of installations of such devices in buildings owned by hundreds of different customers to equal one 100 MW powerplant (see table 12).

Utility executives interviewed for the Theodore Barry survey cited above report that they are relying more and more on non-powerplant options to meet the needs of future growth but they still have concern about their long-term effectiveness (90). Without extensive metering of components of individual buildings, and extensive data collection on occupancy and patterns of use, it is difficult to determine how much of a given building's change in electricity use is due to load management devices and how much is due to other reasons that may be short-lived or unpredictable.

Utilities seeking to avoid costly capacity additions might also work to encourage power production by cogenerators and other small power producers in their service territories. (The potential for cogeneration to reduce electricity demand was discussed above in the section on electricity demand.)

However, current estimates of market potential for small power producers are several times higher than estimates of the central generating capacity that could be displaced by small producion. This is because utilities can use small power production to displace additional central station generating capacity only if it can be counted on to occur at times of peak demand. A recent CRS study estimates the total capacity displacement potential from cogeneration, wind, and small hydroelectric as ranging from about 5 GW to about 22 GW, even though the market potential for cogeneration and wind totals about 63 GW and the technical potential for small hydroelectric is estimated at over 45 GW (14). OTA recently estimated the full technical potential for cogeneration as even higher, 200 GW (72).

It is worthy of note that the estimated market potential for cogeneration alone of about 42 GW is one measure of the market for using HTGRs for cogeneration. As is discussed further in chapter 4, HTGRs operate at far higher temperatures than do light water reactors and can be used to supply steam and pressurized hot water. The resulting high efficiency of operation and production of both electricity and steam for sale can offset their somewhat higher capital cost.

Implications for Federal Policies

As long as electric utilities are regulated there is great potential to influence the strategic choices they make by adjusting the way expenses and investments are handled in electricity rate determination. This report does not analyze all the possible ways in which utility strategies other than central station powerplant construction can be influenced, but it should be recognized that Federal and State regulation can be structured to encourage cogeneration, conservation and load management, and upgrading of central station powerplants.

Utilities have several reasons to wait before ordering more powerplants. The current high reserve margins are one reason, and uncertainty about the future growth of the economy and

Table 12.-Cost and Volume of Various Load Management Devices (controlled by utilities)

Device	Estimated number of installations to equal 100 MW reduction in peak demand	Cost/ installation	Approximate cost/kW
Water heater time switch	91,000	$130-$240	$118-$218
Radio and ripple control (cycles water heater, air-conditioners)	71,000 (water heaters) 93,000 (air-conditioners)	Radio $95-$108 Ripple $100-$115	$67-$107

SOURCE: Table published in OTA study *Energy Efficiency of Buildings in Cities;* based on John Schaefer, *Equipment for Load Management 1979;* and other sources in contract report to the Office of Technology Assessment by Temple Barker & Sloane.

its impact on electricity demand is another. Although electricity demand forecasting is a tricky business at best, there is reason to believe, from both a "top-down" and a "bottom-up" approach to demand forecasting, that electricity demand growth will be slower in the 1980's than it will in the 1990's.

Each of the utilities, influenced by its State PUC will make decisions about the proper rate and type of generating capacity to add. What these individual decisions add up to in terms of a national electric grid depends on the balance among individual utility construction decisions. For example, if all utilities choose to minimize capital requirements and depend on purchase power arrangements, the national reserve margin would drop dangerously low and there could be a scramble to build plants quickly. There could be a short period of unreliable electricity supply. On the other hand, if all utilities chose to build long leadtime generating capacity to meet forecasts of rapid growth in electricity demand, and demand growth failed to increase as forecast, the current high reserve margins might reappear. From a national point of view, it might be best if the different States and utilities adopted a mixture of these approaches.

From a perspective of long-range industrial policy, there may be reason for the Federal Government to encourage steps that make electricity rate regulatory policies handle inflation better, and insure stable electricity prices over the long term (see box C). Although average electricity rates are forecast to increase smoothly and slowly over the next one or two decades, this masks a set of offsetting roller coaster rides for individual utilities, that is reflected clearly in the differences among forecasts of regional electricity rates (mentioned in the section on electricity demand above). In times of high inflation, utilities bringing new powerplants online have rapidly increasing rates for several years and then slowly decreasing rates. The increasing rate phase may discourage the location of industries, which might benefit over the long run from the declining rate phase.

At the moment, if rate regulatory policies across the country were to shift to favoring longer leadtime, capital-intensive technologies, coal-fired generation would be encouraged far more than nuclear powerplants because utility executives seem to prefer the smaller size, shorter leadtimes, lower financial risk, and greater public acceptance of coal. The implications for the nuclear industry are bleak, and read as such by the industry (87). Only a handful of orders for central station powerplants of any kind is likely before 1990. After that, if a modest number of powerplants are needed, 10 to 15 GW/yr, coal may seem adequate (unless there is a dramatic change in attitudes and public policy about the impacts of coal-burning on acid rain and carbon dioxide buildup, and no significant improvement in coal-burning technology).

If the amount of new capacity needed is much larger, however (up to 30 GW/yr), utilities may look to nuclear again as a way of diversifying their dependence on a single technology (coal). In addition, now that natural gas shortages appear less likely over the next decade, it is also possible that combustion turbines, particularly high-efficiency combined cycle plants will seem to be acceptable sources of diversity. For those reluctant to continue such reliance very long, or to depend heavily on so-called new technology there could be renewed interest in new nuclear plants beginning in the 1990's. By that time if the construction and operating risks of nuclear are significantly better than they seem to utilities now, or if alternatives, namely coal, are significantly worse, utilities may place orders for more nuclear plants. In particular, if nuclear plants can "match the market more" (in the words of one OTA workshop participant) and come in smaller sizes, with shorter leadtimes and predictable costs, they might be a competitive option again for supplying electric-generating capacity.

Appendix Table 3A.– Estimated Costs of Nuclear Plants Under Active Construction in the United States[a]

A. 95°/0 or more complete:	
Diablo Canyon 1, 1,064 MW, Pacific Gas & Electric	$1,700/kW
Shoreham, 819 MW, Long Island Lighting Co.[b]	$4,500 +/kW
Wm. H. Zimmer, 810 MW, Cincinatti E & G	$3,900/kW
Grand Gulf 1, 1250 MW, Mississippi P&L	$2,300/kW
Palo Verde 1, 1270 MW, Arizona PS Co.	$2,300/kW
McGuire 2, 1160 MW, Duke Power Co.	$830/kW
B .90-95 °/0 complete:	
Waterford 3, 1,104 MW, Louisiana P&L.	$2,400kW
Diablo Canyon 1, 1,106 MW, Pacific Gas & Electric	$1,700/kW
Limerick 1, 1,1055 MW, Philadelphia Electric Co.	$2,900/kW
La Salle 2, 1,078 MW, Commonwealth Edison	$1,100/kW
Catawba 1, 1,145 MW, Duke Power Co.	$1,700/kW
WPPSS 2, 1,100 MW, WPPSS	$2,900/kW
Comanche Peak 1, 1,150 MW, Texas Utilities (Dallas)	$1,700/kW
San Onofre 3, 1,100 MW, Southern California Edison	$1,900/kW
Fermi 2, 1,100 MW, Detroit Edison	$2,800/kW
C. 80410°A complete:	
Clinton, 950 MW, Illinois Power Co.	$3,000/kW
Byron 1, 1,120 MW, Commonwealth Edison[b]	$1,500+/kW
Watts Bar 1, 1,177 MW, TVA	$1,500/kW
Palo Verde 2, 1,270 MW, Arizona OS Co.	$2,300/kw
Callaway, 1,150 MW, Union Electric of Missouri	$2,500/kW
Bellefonte 1, 1,213 MW, TVA	$2,300/kW
Wolf Creek, 1,150 MW, Kansas G& E/K.C. P&L	$2,300/kW
Perry 1, 1,250 MW, CAPCO Group (Ohio)	$2,200/kW
Midland 1, 522 MW, Consumers Power, Michigan	$2,700/kw
D .50-600/' complete:	
Midland 2, 811 MW, Consumers Power[b]	$2,700 +/kW
Bellefonte 1, 1,213 MW, TVA	$2,300/kW
Byron 2, 1,120 MW, Commonwealth Edison[b]	$1,500+/kW
Seabrook 1, 1,500 MW, P.S. Company of New Hampshire	$2,800/kW
Watts Bar 1, 1,177 MW, TVA	$1,500/kW
Braidwood 1, 1,177 MW, TVA.	$1,500/kW
Comanche Peak 2, 1,150 MW, Texas Utilities.	$1,050/kW
Harris 1, 900 MW, Carolina P&L	$2,500/kW
Beaver Valley 2 MW, 644 MW, Duquesne Lighting Co. (Pa.)	$3,700/kW
Susquehanna 2, 1,050 MW, PA Power & Light Co.	$1,900/kW
Nine Mile Pt. Pt. 2, 1,065 MW, Niagara Mohawk	$1,900/kW
Hope Creek 1, 1,67 MW, Public Service E&G (N.J.)	$3,600/kW
Braidwood 2, 1,120 MW, Gulf States Utilities.	$1,400/kW
River Bend 1, 934 MW, Gulf States Utilities	3,700/kW
Millstone 3, 1,150 MW, Northeast Utilities	$3,000/kW
E. 49-59°10 complete:	
South Texas 1, 1,1250 completed	$3,000/kW
Marble Hill 1, 1,130 MW, PS Co. of Indiana[b]	$3,100 +/kW
Palo Verde 3, 1,270 MW, Arizona P.S Co.	$2,300/kW
Perry 2, 1,250 MW, CAPCO Group (Ohio)	$2,200/kW
Catawba 2, 1,145 MW, Duke Power Co.	$1,700/kW
Vogtle 1, 1,150 MW, Georgia Power Co.	$2,700/kW
F. Around 20°/0 complete:	
Marble Hill 2, 1,130 MW, P.S. Co. of Indiana[b]	$3,100 + /kW
South Texas 2, 1,250 MW, Houston L&P.	$3,100t/kW
Vogtle 2, 1,150 MW, Georgia Power Co.	$2,700/kW

[a]Cost data as of December 1983, in mixed current dollars. Construction completion as of October 1982.
[b]"+" is added where costs are likely to go higher than utility estimates.
[c]Physically 95% complete, but potentiality subject to major rework.

SOURCE: Data compiled by Charles Komanoff for a paper by 1. C. BUDD and Charles Komanoff. The source of data is utility estimates of cost of complete nuclear plants. The costs are in "mixed current dollars," the sum of dollars spent In each year plus applicable capitalized interest. They are not mutually comparable due to different accounting conventions for items such ss "construction work in progress" and interest capitalization and different time perlods. See ch. 3 for a discussion of comparable costs of these Plants. Fully comparable data will be published in early 1984 by Komanoff Energy Associates.

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