The Electricity Industry's Dilemma

Haunted by cost overruns and faced with uncertain forecasts, utilities are shelving construction; some analysts are predicting trouble ahead

In May, the Long Island Lighting Company asked Brookhaven National Laboratory if physics experiments that devour 25 megawatts of electrical generating capacity would be damaged if power were shut off. Across the country, Nevada Power Company executives are waiting for the next power outage on the overloaded Pacific Northwest transmission grid. And in Birmingham, Alabama, managers of the Southern Company are planning for the day when the utility can reclaim for its customers 4000 megawatts of power now sold to Florida and Gulf Coast utilities.

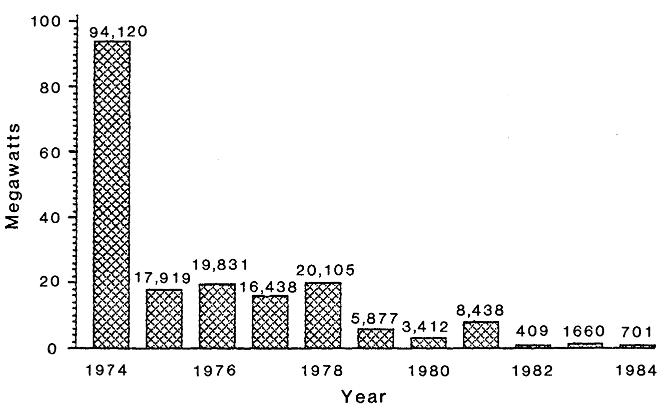
These examples suggest that the United States is about to run out of electricity. This is not going to happen in the next few years, but beyond that nobody knows. Forecasting electricity demand has become a highly uncertain business.

Twenty years ago making a decision to add generating or transmission capacity would have been fairly straightforward. Today the problem is immensely more complicated. Uncertainty about national and regional economic growth, conservation, and small power generation have caused many power companies to shelve building plans. Wary that investor confidence in electric utilities has been eroded by massive cost overruns and falling growth, power companies are understandably adopting a low-risk, least-cost strategy for meeting power demand.

"There is a new generation of managers coming in," comments Michael Bergman, staff engineer with the American Public Power Association (APPA), which represents municipal power systems. "They are deferring capacity additions and continuing with load management when possible." This attitude appears to be reflected in power company decisions to cancel 23,000 megawatts worth of new generation in 1984.

Yet utility planners are increasingly worried about brownouts and blackouts during peak periods of power demand—as early as the late 1980's. The nation as a whole will not be affected. But a pinch could come in parts of New England, the Gulf Coast, Florida, and the Northwest and Midwest where surplus generating capacity is shrinking and power transmission links are strained.

Uneasy with the outlook, utility industry leaders are moving to arouse public and political interest in the issue. "There is not enough capacity being planned to replace aging plants and to support economic growth," asserts William McCollam, Jr., president of the Edison Electric Institute (EEI). Unless new capacity is erected, says the head of the 176 member investor-owned utility trade group, consumers may end up paying more for power than necessary because utilities will turn to costly gas and oil-fired generation to close the supply gap.



New orders for power plants have been sparse in recent years due to slack demand and surplus capacity. Data for 1984 is based on orders for 6 months. [Source: Edison Electric Institute]

Economic expansion also could be constrained and jobs lost as a consequence of short supplies or high costs, McCollam told electric utility executives assembled at EEI's annual meeting in June. McCollam and power company executives are anxious about the situation because there are few new orders for power plants, which take 8 to 15 years to construct. To avoid trouble in the near future, says McCollam, utilities must start new projects soon.

Through 1994 the installed generating capacity "will be near minimum acceptable levels," says David R. Nevius, assistant to the president of the North American Electric Reliability Council (NERC). Peak demand is expected to rise from 465,100 megawatts to 566,800 megawatts by 1994. In the United States, according to NERC, power companies are planning to install 107,000 megawatts of capacity by 1994—bringing total capacity to 704,300 megawatts. However, this is a marked reduction in planned addition from 2 years ago when 175,000 megawatts were scheduled.

This means reserve margins for actual demonstrated capacity will fall below 21 percent. This is the minimum reserve margin utilities usually need to deal with weather-related spurts in demand, sudden shutdowns, and scheduled maintenance. "The industry is in a precarious position to cope with demand that exceeds forecasts for the 1990's," notes Nevius. And analysts note that, with time, capacity reserves will erode further because plant efficiencies and availability deteriorate with age.

Although many of their members are unwilling to proceed with new starts now, APPA, EEI, and the National Association of Regulatory Commissioners are campaigning to get Congress and state utility commissions to focus on the industry's long-term generating needs before a crisis is at hand. In particular, officials seek regulatory reforms to speed plant siting, cut construction lead times, and assure cost recovery.

Except for predicting load growth, utilities' biggest problem may be the regulatory uncertainties of state utility commissions. Increasingly, these regulatory bodies are critical of utility planning that results in excessively high reserve margins. In Massachusetts, for example, the Department of Public Utilities (DPU) has adopted a "used and useful" principle. If a power company builds and demand estimates turn out high, some construction costs might not be rolled into customer's electric bills.

"The DPU is shifting the risk from the ratepayer to the utility's stockholders," says Robert J. Cuomo, head of Boston Edison's division of forecasting. Faced with this reality, Boston Edison is not building any new capacity, although it is refurbishing a 400-megawatt coal-fired plant. "It does not make sense to put our stockholders at tremendous risk," says Cuomo, commenting on the regulatory outlook.

Instead, the utility plans to meet demand, which has been growing at an average of 4 to 5 percent annually, by hiking Canadian power imports from 196 megawatts today to 571 megawatts by 2000. Boston Edison's approach is not atypical of utility behavior in the United States. "There is a lot of confusion out there," says Nevius. "Many utilities are taking a wait and see attitude on new construction, especially those that have gotten burned."

Working against the industry's campaign are power surpluses produced by overbuilding and in many instances rate shock resulting from skyrocketing plant costs. Ironically, these problems were preceded by two decades of utility industry drum beating about coming power shortfalls.

"Our members are under intense competitive pressures from overseas manufacturers," says Russell J. Profozich, senior economist with the Electricity Consumers Resource Council (ELCON), which represents industrial users. Noting that some nuclear capacity coming onstream will cost $4000 per kilowatt, he says, "You can't compete with electricity prices at that level."

Electricity sales in the decade preceeding the 1973 Arab oil embargo were growing at an annual rate of 7.4 percent, but the energy crisis and economic downturn of the last 10 years have caused national growth rates to slow. After jumping up to 5.7 percent as the economic recovery took off in 1983, growth rates slid to 3.4 percent in 1984 and may fall below 3 percent for the rest of the decade.

To help get regulators and policy makers to look beyond current capacity surpluses, the industry in recent months has pressed for a presidential commission to study the issue. The White House balked, but the Department of Energy (DOE) may soon take up the matter.

Members of Congress are beginning to show interest in sorting through the utility industry's assertions. Senator James McClure (R–Idaho), chairman of the Energy and Natural Resources Committee, has scheduled hearings 23 and 25 July. Representative Edward J. Markey (D-Mass.), chairman of the House Energy and Commerce Committee's subcommittee on energy conservation, will be probing how utilities plan for load growth in late August or early September.

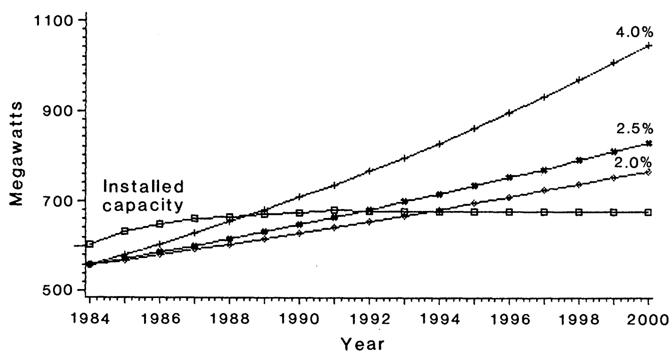
Conservationists and environmentalists, who advocate using energy more efficiently, are sure to use these hearings to warn against overbuilding. They will likely be joined by consumer groups that also will be as skeptical. "The utilities have been predicting doom and gloom since the 1970's. We just do not see any looming crisis on the horizon," says ELCON's Profozich.

While past industry load-growth projections were often high, relying on current capacity and conservation could prove inadequate, says Bill M. Guthrie, executive vice president of Southern Company Services, Inc. "A lot of people are going to start running out of capacity by the late 1990's," says Guthrie. The Southern Company, the nation's second largest utility holding company, will need 4000 megawatts of power that is currently being sold to other utilities—and still may have to build additional capacity assuming a growth rate of 2.5 percent annually, Guthrie says.

Had power companies broadly embraced conservation and load management programs earlier, says Karl Gawell, an energy lobbyist for the National Wildlife Federation (NWF), they might have had more maneuvering room. California, for example, has had an aggressive conservation planning program for more than a decade. Pacific Gas and Electric (PG&E), for example, has displaced the need for some new power plants through conservation and load management programs. Stiff standards for household appliances alone will achieve savings of 2000 megawatts by 2005. Conservation and load will achieve another 3300 megawatts in savings, says Richard E. Rohrer of PG&E.

But conservation is not a substitute for new generation and transmission capacity in many parts of the country, says John W. Arlidge, vice president of resource planning for Nevada Power Company. "It is something you have got to do and you are going to do it, but it does not take the place of everything." Sunbelt states will continue to grow at a faster rate than the rest of the country, he observes.

McGraw-Hill's Data Resources, Inc. (DRI) estimates that demand will grow 2.9 percent in 1985 and at an annual rate of 3.1 percent to the end of the decade. In the 1990's, the DRI expects the rate of growth to slow further. Similarly, NERC predicts that, over the next 10 years, electricity use will climb an average 2.4 percent annually. This is a reduction from 2.7 percent in 1984.



Even at low rates of growth, electricity demand could outstrip supply by the mid-1990's. [Source: Edison Electric Institute]

DOE's Energy Information Administration is a bit more bullish. The agency sees annual growth rates of 3.4 percent to 1990 and a falloff to 3.1 percent through 1995. DOE also observes that a pickup in the national economy could quickly drive electricity growth rates to 4.1 percent for the 1985–1990 time frame.

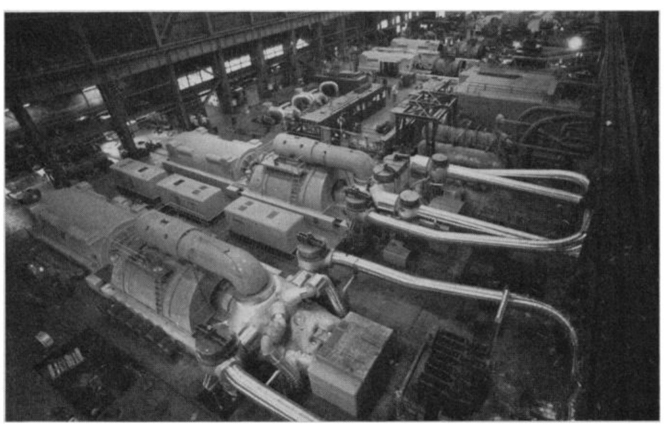
Even though it appears that demand will strain some utility systems by the mid-1990's, the impact of this growth could be blunted, if not dissipated, by nonutility power producers, such as manufacturers that cogenerate heat and electric power, and small hydroelectric companies. The NERC sees cogeneration being important in four areas: New England, California, Texas, and the mid-Atlantic Coast states. But it sees just a total of 10,000 megawatts being added by 1994—most of it in Texas and California.

The Department of Energy, however, estimates cogeneration potential at 39,000 megawatts with most of the capacity captured in the paper, textile, chemical, fossil energy, and metal industries. An estimated 14,000 megawatts of cogeneration already is in place, but the long-term success of cogeneration will be tied to what it costs power companies.

For utilities to fully exploit congeneration, says John Eustis, an analyst with DOE's Office of Waste Energy Reduction, "you have got to let them make money." The nature of the utility business is changing, says Eustis, noting that "utilities are going to become merchants of power." They will buy cogenerated power if it is priced right, contends Eustis, who notes that fees utilities are legally required to pay private power producers may be excessive in some states.

Utility executives, however, are quick to point out that not all of this capacity power is reliable or usable. "When you start trying to rely on small power to meet demand, you have to ask whether they are really going to be there to meet the load," says Southern's Guthrie. "It really depends on what kinds of commitments these people [small power producers] are willing to make to the utility."

The potential for cogeneration and small power production also may decrease with changes in variable costs formulas. Frequently, the rate is equivalent to a utility's cost of generating that increment of power—the so-called avoided cost rate. And in parts of the country these costs have decreased as coal-fired generation has displaced oil, or of late as oil prices have dropped.



Steam turbine room

Utilities canceled plans to build 23,000 megawatts of generation in 1984.

"What you are finding is that a lot of the investment is based on avoided costs," says Kenneth A. Schweers, senior vice president with ICF, Inc., a Washington, D.C., energy consulting firm. "When we go back and factor in all the uncertainties, we find that avoided costs will be a lot lower than what people frequently have used to justify investment," adds Schweers. Some forms of cogeneration or small power production may have a short future because cheaper baseload or bulk power may become available.

The way many utilities plan to meet demand and avoid unnecessary risks is to buy power under long-term contract and purchase so-called "economy power" when it is available. Such sales have increased dramatically in the past 20 years and will increasingly be relied on in parts of the Northeast, Northwest, South, and Southwest. Undermining this approach though is inadequate transmission capacity and difficulties in erecting new capacity.

In the Pacific Northwest, for example, a major transmission line carrying bulk power to California, Utah, and other parts of the West is operating at 150 percent of its rated capacity. The system kept working with gadgets—relays, capacitors, and complex multi-utility load-switching strategies. The problem with this approach to managing transmission loads is that you can go too far, says Dennis E. Eyre, administrative manager for the Western States Coordinating Council.

"When things [fail], more than one thing tends to happen and you end up with 'islanding'—the breakup of the system," notes Eyre. "Everyone agrees the failure rate has been too high in the West." And for the near-term transmission reliability in many parts of the United States will only get worse.

Regions with transmission bottlenecks or strained systems include the Southwest, southern California, Pacific Northwest, upper Midwest, New England, and the Middle Atlantic states. Construction of new transmission has been delayed by regulatory obstacles at the state and federal levels, and by environmental concerns. But new transmission projects also are being shelved due to doubts about whether demand will materialize and investments can be recouped. Power companies' cautious approach is not unjustified says Eyre, noting that "in the 1990's, a lot of things can change."

Indeed, it is hard to predict the United States' rate of economic growth for the next 10 years, much less after 1995, says Ben J. Wattenberg, senior fellow with the American Enterprise Institute and the former director of the United States Census. He recently reminded EEI's membership that the population is aging and that there is not a second baby-boom wave to drive economic expansion like that which followed World War II.

The implications of this demographic change for the American economy and for electricity demand are not clear. It suggests, says Wattenberg, that the Yuppie generation's conspicuous consumption of consumer goods and housing may level off in the next 10 years or so. Thus, new demand for power may slow. But flat population growth also could lead to labor shortages. Greater mechanization of factories could be required, and this would be electricity intensive.

DRI, in its Electricity Outlook, predicts that commercial and industrial electricity demand will keep pace with real gross national product. GNP growth does not slow as fast as growth in the labor force because older workers will be more productive, says Larry Makovich, a senior energy economist at DRI. Nonresidential sales of electricity—in electric intensive industries and the commercial sector—will lead growth for the remainder of the century. Residential demand for power will expand at a slower rate as new housing sales fall in conjunction with lowered population growth, Makovich notes.

To cope with uncertainty about the future, utilities are looking to new power-producing technologies that can be brought on line quickly, in less costly increments of several hundred megawatts. The most prominent technologies are: integrated combined-cycle gas-fired turbines, pressurized fluidized-bed combustion, and atmospheric fluidized-bed combustion. Much of this equipment could be manufactured in factories rather than on site and in some cases could be erected in a few years.

But even though some of these systems are being demonstrated on a commercial scale, there are signs that utilities may hesitate to experiment. "What is it going to take to prove that the risks are acceptable as far as putting it on your system?" asks Nevada Power's Arlidge. "Is the technology that sound?"

Remarks Raymond J. O'Connor, chairman of the Federal Energy Regulatory Commission, "The proliferation of so many conflicting futures underscores massive uncertainty about demand growth, construction costs, alternative technological options, and regulatory policies."

Indeed, NWF's Gawell ventures that new construction may not go forward until the need is obvious. Utility executives efforts to balance financial goals against building amounts to gridlock. "They are in an untenable position," says Gawell, in sizing up the situation. "The last person I would want to be today is a utility executive."

—MARK CRAWFORD