The Value of Reliability

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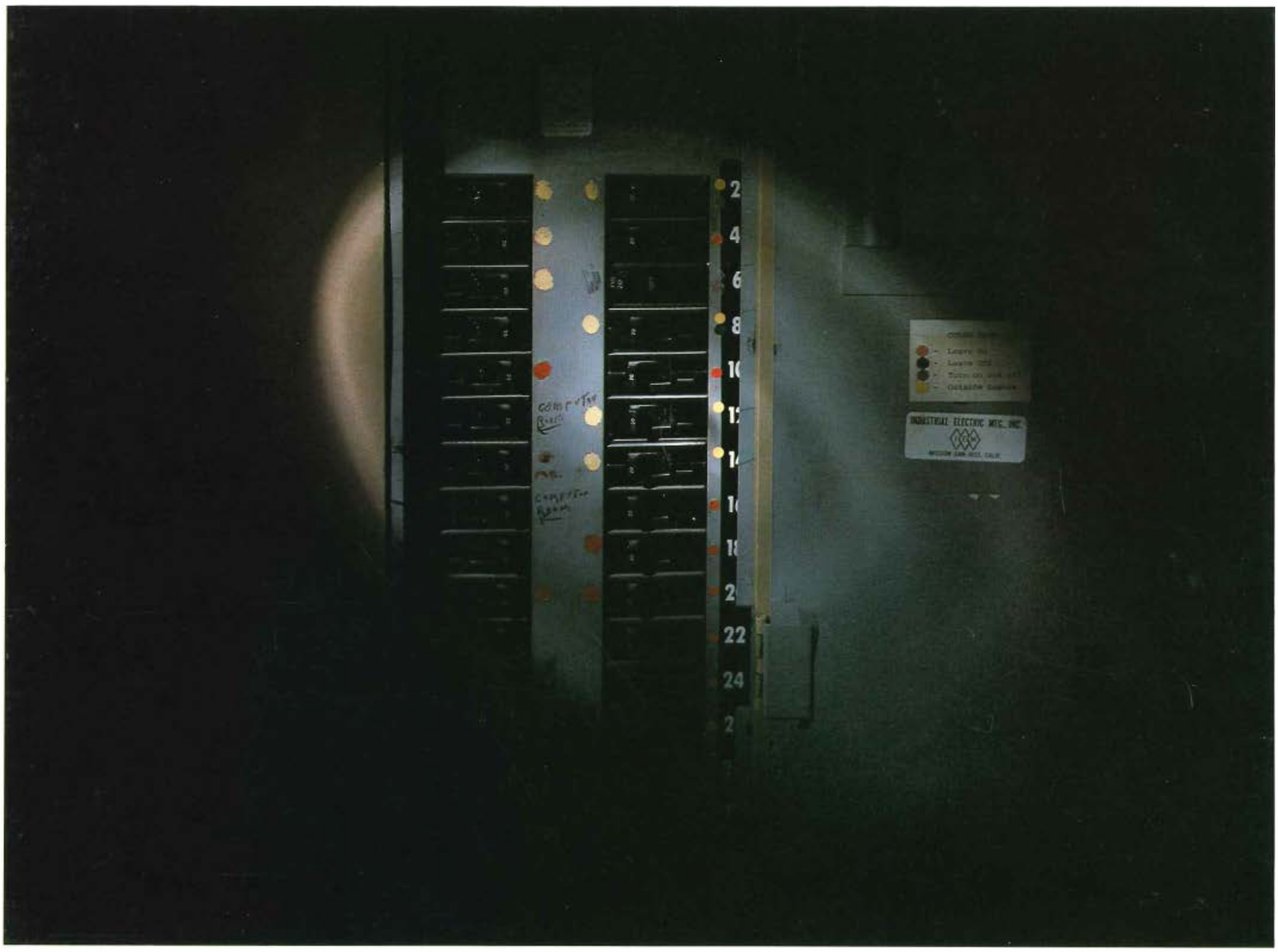

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Cover: When the lights go out, the problem isn't always with your circuit breakers. Reliability of utility service—what it costs to provide and how much value customers place on it—is getting close attention.

EPRI JOURNAL

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Meeting the Reliability Challenge

Balzhiser

Reliability has always been a point of pride for electric utilities—the touchstone of responsible planning and a distinguishing attribute of high-quality service. To preserve system reliability, American utilities have traditionally planned capacity expansion sufficient to reduce the related loss-of-load probability to one day in ten years. Comparably stringent standards have also been applied to the construction of transmission and distribution networks, thus creating one of the world's most reliable electric power systems.

Today, however, this reliability is being challenged more seriously than at any time in several decades. Rising costs, financial and regulatory constraints, and uncertain load growth have forced many utilities to defer capacity expansion. As a result, according to the North American Electric Reliability Council, generating capacity margins may reach minimum acceptable levels by the mid 1990s.

EPRI can help utilities meet this challenge both by developing new technologies that help preserve system reliability and by producing information on how reliability can be treated more like a marketable commodity in order to keep electricity competitive and to serve the various needs of many kinds of customers. This month's cover story describes some of the research being conducted to determine the value of reliability to customers in various applications and to find ways of establishing a menu of reliability choices that will reflect the differing needs of consumers. Such product differentiation will give individual customers an explicit choice of either receiving a discount on their monthly utility bill in return for more interruptions of service or paying a premium for high reliability where it is most important.

In a highly technology-dependent country such as ours, it should also be remembered that maintaining high levels of reliability of electric power for those who require it is crucial for preserving economic competitiveness and preventing social disruption. Thus national decision makers, as well as electric utilities, may be able to use the new information about the value of electric power reliability in planning for a more secure future.

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Authors and Articles

Chao Barker Gellings Purcell Ricci Peck Young Duffey

The Value of Reliability (page 4) explores electricity customer reactions to different levels of service reliability and outlines new choices coming from utilities. Written by John Douglas, science writer, with researchers from two EPRI divisions.

Stephen Peck joined the Energy Analysis and Environment Division in 1976, became a program manager in 1979, and has been technical director of the Environmental and Economic Integration staff since it was formed in 1982. He was formerly an assistant professor of economics at the University of California at Berkeley. Peck was educated in England and in the United States; he has an MBA and a PhD in business economics from the University of Chicago.

Paolo Ricci was an EPRI project manager for environmental risk analysis from 1979 until the end of 1985, when he took a position with Arthur D. Little, Inc. Ricci was previously an assistant professor at the University of Ottawa for three years and a consulting engineer for six years. Educated in engineering and in economics, he also has a PhD in environmental engineering and science from Drexel University.

Clark Gellings heads a new program in demand-side planning for the Energy Management and Utilization Division. He was previously a program manager for demand and conservation studies in the Energy Analysis and Environment Division. Before 1982 he was with Public Service Electric & Gas Co. for 14 years, first in sales and ultimately as assistant manager for load management. Gellings has an MS in mechanical engineering from the New Jersey Institute of Technology.

Hung-po Chao, a project manager in the Energy Analysis and Environment Division, specializes in economic decision analysis. An electrical engineering graduate of Taiwan University, Chao earned MS and PhD degrees in operations research at Stanford University in 1978 and was a research associate there before he came to EPRI in 1979.

■

New Forces in the Utility Marketplace (page 12), a summary of EPRI's 1985 Advisory Council seminar, focuses on competitive forces that are both motivating and complicating electricity demand management today. Written by **Brent Barker,** editor in chief.

Editor of the *Journal* since he joined EPRI in 1977, Barker was previously with SRI International and U.S. Steel Corp. He graduated in engineering science from Johns Hopkins University and received an MBA at the University of Pittsburgh.

■

The Dynamics of Indoor Air Quality (page 20) discusses research findings on indoor air quality, especially as it is influenced by modern heating systems, building materials, and measures for buttoning up against the winter. Written by Mary Wayne, science writer, with guidance from two EPRI research managers.

Gary Purcell, a project manager in the Energy Utilization Department, has worked mostly with the performance of residential and commercial energy systems since he came to EPRI in 1977. He formerly was with Lockheed Missiles & Space Co., Inc., for 15 years, specializing in aerospace vehicle temperature controls. Purcell, a mechanical engineer, received an MBA at Pepperdine University.

Cary Young, a project manager for health studies, came to the Environmental Assessment Department in 1980 after three years as a senior medical scientist at SRI International and six years with the U.S. Public Health Service. He has an MD from Baylor University and an MPH from Johns Hopkins University.

■

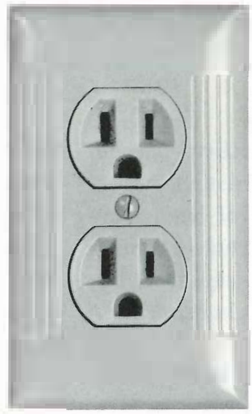
Reevaluating Nuclear Safety Margins (page 26) explains how research to quantify nuclear reactor phenomena under loss-of-coolant accident conditions is making it possible to revise overly conservative regulations. Written by John Douglas, science writer, with information from EPRI's Nuclear Power Division.

Romney Duffey is a senior project manager in the Safety Control and Testing Program of the Safety Technology Department. Trained as a physicist, Duffey came to EPRI in 1977 after 10 years with Great Britain's Central Electricity Generating Board. He has a PhD in physics from Exeter University (England).

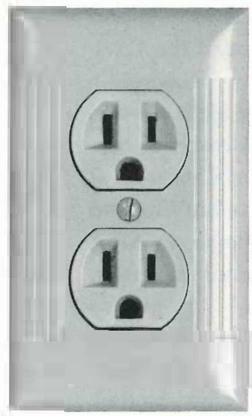
The Value of Reliability

How important is service reliability to consumers of electricity? Studies show wide extremes of perceived value, and utilities are developing marketing approaches and pricing structures that allow customers to choose among various levels of service.

Reliability 50 × greater
Pay $3/kW more per month



Reliability 10 × greater
Pay $1/kW more per month



Standard reliability
Standard cost

Reliability 5 × lower
Pay $1.50/kW less per month

Reliability 15 × lower
Pay $3/kW less per month

Around the turn of the century utility rates were designed to promote the use of electric power by emphasizing its unique advantages and inviting direct cost comparisons for specific end uses. One utility, for example, offered monthly rates of 50¢ apiece for each electric lamp in an office, 75¢ for each store lamp, and $1 for each saloon lamp. Energy for an electric ceiling fan cost $6 per season. The use of such service-specific rate options gradually declined as electricity became less expensive and as consumers were increasingly attracted by the convenience and reliability of electric power.

Now, in an era of escalating energy costs and uncertain load growth, utilities are again beginning to use innovative rates to keep electric power competitive and shape load characteristics. Rather than pegging these rates to specific end uses like saloon lights, however, some utilities are working closely with their customers to devise innovative ways of pricing a key attribute of electric power—reliability itself. For customers, such rates can mean a more cost-effective match between the type of electric service required and the level of reliability provided. For utilities, a rate structure based on the value of reliability can enhance the competitiveness of electricity compared with other forms of energy. The price changes can also be used either to promote load growth where generating capacity is ample or to reduce peak demand where capacity margins are tight.

The reliability of electric power in the United States is, of course, very high, and the new emphasis on its intrinsic value has raised a host of issues that will require extensive research to resolve. How can reliability best be evaluated and how do customers perceive its importance compared with other attributes of electricity? What new marketing approaches will be needed to introduce rates based on reliability? Can new technologies help separate specific end-use applications for rating or curtailment purposes? How do reliability considerations affect both demand-side and supply-side planning? EPRI now has research projects addressing each of these concerns, which are discussed in this article. A future article will cover EPRI research to help utilities maintain and improve system reliability under current constraints.

The reliability dilemma

Maintaining a reliable supply of electricity requires an adequate amount of various types of generating capacity. In recent years, however, work on many proposed generating plants has been delayed or curtailed, and utilities have been reluctant to plan further capital-intensive capacity additions. As a result, reliability in the future can no longer be taken for granted, and increased power outages of some sort may eventually become inevitable.

This point was stated in particularly unambiguous terms in the *1985 Reliability Review* of the North American Electric Reliability Council (NERC). In this review, NERC said it "expects the reliability of electric supplies to decline over the next 10 years. By the mid 1990s, electric generating capacity margins will be near minimum acceptable levels in some parts of the United States, even if electricity demands grow no faster than the present forecast rate of 2.2% per year."

When reliability declines, costs rise. Case studies from the EPRI over/under capacity model, published in 1978, showed that a utility's optimal reserve margin is determined by the trade-off between outage costs and the costs of increasing capacity. The optimal reserve margin occurs when the sum of these costs reaches a minimum, but the cost curve is not symmetric about this point. Total cost to customers generally increases rapidly when reserve margins fall too low but rises rather slowly with additional capacity. The reason for this asymmetry is that expensive outages occur with steeply increasing frequency below the optimal reserve level, while capital costs above this level tend to rise linearly. The optimal capacity margins and lowest total customer costs for specific utilities studied in this project were shown to be affected significantly by the average cost of an unserved kilowatthour and to lie approximately in the range of 20–30% of reserve level. Current research is investigating how total customer costs might vary with the mix of demand-side and supply-side options.

This general conclusion was underscored in a special report, prepared for NERC by EPRI in 1984, addressing the question of whether current capacity margins are adequate to sustain the U.S. economy for several more years. The report showed that of the national average 25% capacity margin prevailing during the summer demand peak of 1983, about 15% was actually unavailable because of maintenance, forced outages, and deratings. That left only a 10% operating margin to prevent power interruptions that might result from sudden equipment failure or daily fluctuations in demand. Maintaining an adequate operating margin also helps lower costs by enabling utilities to maximize the amount of power generated at their most efficient plants. The report concluded, "By the end of the decade, new capacity will be needed to provide a dependable supply of electricity for economic growth."

For a variety of complex reasons, much of this new generating capacity may not be built within the time required to prevent significant loss of reliability. During recent years, the allowed rates of return on investment in new power plants have often fallen below the cost of capital, so that utilities have become increasingly reluctant to expand their generating capacity. "Our models have shown that a properly selected electricity price structure can induce utilities to invest in new capacity at a rate that is simultaneously optimal for both the customers and the utility owners," says Stephen C. Peck, technical director of the Environmental and Economic Integration Staff. "At present, however, utilities enjoy few incentives and confront substantial risks when planning such investments. They face a real dilemma in trading off their customers' interest in high reliability with the owners' interest in getting an adequate return on investment."

Cost of outage

The reliability dilemma contains several imponderables, including load growth uncertainty and the growing importance of cogenerated power, which may obviate the need for generation expansion in some areas for several years. In spite of such factors, however, the utility industry is clearly beginning to attach new importance to reliability as a commodity that can be differentiated, priced, and marketed. By doing so, a utility can most likely improve its utilization of existing power plants and thus reduce the total amount of capacity it must build. A first step in this process is to determine more precisely what costs are incurred when the limits of reliability are reached.

Electricity outages occur in two different ways—unscheduled interruptions and controlled curtailments. Most interruptions currently result from temporary problems involving a utility's transmission and distribution system, not its generating capacity. The usual cause is either a fault, as when a tree topples onto a power line, or the failure of some piece of utility equipment. As reserve margins diminish, however, an increasing number of interruptions may be caused by energy shortages that occur when available generating capacity is insufficient to meet a demand peak. In such circumstances, a utility may be able to reduce demand by curtailing service to specific customers or specific end uses. Customers with curtailable service can be compensated by having a lower rate. Setting such rates requires a knowledge of many factors, including how much outages cost customers.

Although the aggregate costs of blackouts are dramatically apparent (the short-term estimated cost of the 1977 New York City blackout was $350 million), costs of outages to individual customers have been hard to quantify. To bring together available information on such costs, EPRI sponsored a seminar in 1983 to evaluate various methods of cost estimation. The papers delivered as part of this seminar have now been published as an EPRI report.

In this report the wide range of costs that may result from outages is particularly apparent from customer surveys conducted by Ontario Hydro. For a 20-min outage, an average cost per kilowatt of load (in 1980 dollars) was reported to be only 4¢ for residential customers, $2.46 for large industries, and $6.72 for office buildings. The length of time required for an advance warning to help customers reduce costs also varied widely—from a few minutes to 19.5 hours—even among large industrial users.

A more detailed analysis of how outages affect industrial customers is provided by a Tennessee Valley Authority (TVA) study based on information gathered from on-site interviews. The study assumed that if outages are expected, companies will begin to spend more on mitigation efforts, such as purchasing backup generators. For interruptions in which most of a company's load still receives electricity, the cost of adopting mitigation measures is relatively high, and the damage cost from the outage remains rather low. Conversely, when virtually all outside electric power is shut off, damage costs are highest, and the relative cost of mitigation is lower.

Somewhere in between, the total outage cost (damage plus mitigation) reaches a minimum. Being able to calculate this minimum for specific industrial processes and for outages of varying frequency and duration can help both manufacturers and utilities prepare for anticipated reliability problems. Among six industrial plants studied by TVA, for example, it was found that the average minimum cost of a three-hour interruption once a year was $324,000, while that of 10 one-hour interruptions per year was $396,000. The study also found that total outage costs for industries in which mechanical drive was the major end use were from 3 to 10 times higher than costs for industries that used electricity in furnaces or electrolysis.

Customer perceptions of reliability have been studied in focused group sessions and in-depth interviews by the Empire State Electric Energy Research Corp. (Eseerco). The study found that customers are generally satisfied with current levels of reliability and generally see outages as "acts of God," beyond the control of utilities. Customers are concerned, however, about the frequency and length of outages, responding generally that four or more outages a year or a single outage of more than eight hours would be undesirable. Timing of an outage in terms of hour of the day, day of the week, or season of the year was found to be more important to industrial than to residential customers. The study concluded that customers generally would accept some loss of reliability if their electric bills could be significantly reduced.

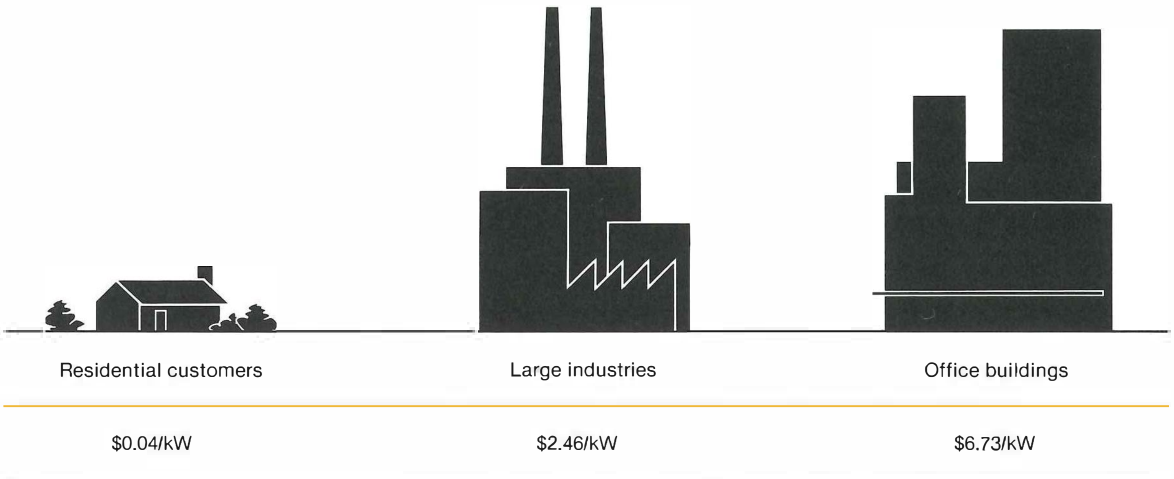
"Such studies help provide a data base that utilities can use in working with their customers to reduce the cost of outages," explains Paolo Ricci, project manager. "We must remember, however, that there are many social factors that transcend such quantitative analysis and cannot be captured in the calculated costs. Health effects, social unrest, and national energy dependence must also be taken into account."

Value-based planning

Determining acceptable levels of reliability as a distinct commodity depends on its perceived value in specific applications. Faced with increasing curtail-

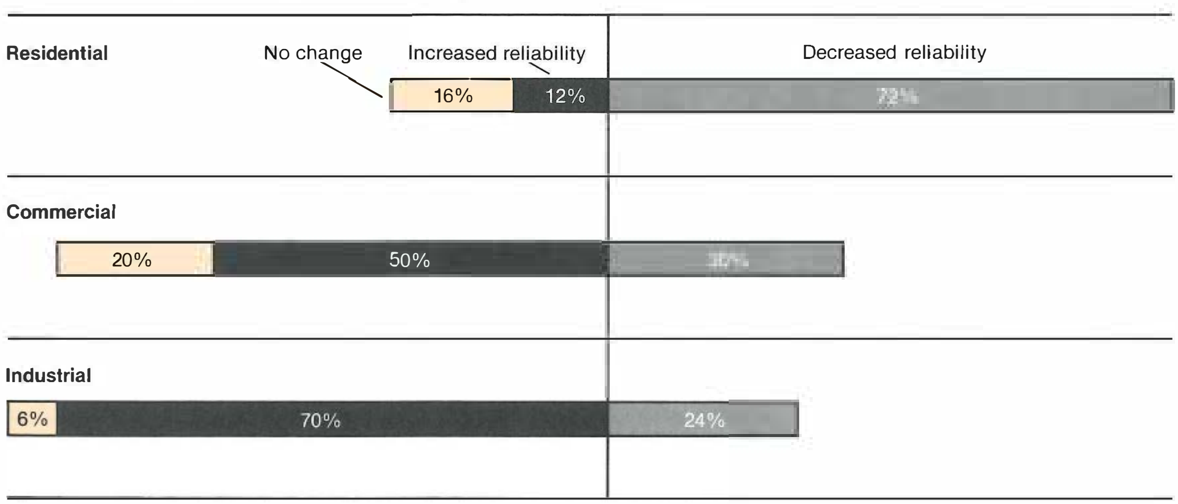
The Cost of Outage

Surveys conducted by Ontario Hydro show that the cost of not having electricity available on demand varies drastically between and within user sectors in their service territory. The cost of a 20-min power outage is only pennies per kW of load in the residential sector, where such an event is seen primarily as an inconvenience. In a large commercial office building, where the productivity of hundreds of workers is affected, the cost of the same interruption averages $6.73/kW. Costs of outages in industrial plants average $2.46/kW but they can vary by a factor of 10, depending on how electricity is used in the plant.



Customer Preference for Reliability

A Pacific Gas and Electric Co. survey asked customers which of three reliability-cost trade-offs they would prefer, if offered: a 10% reduction in electric rates with double the number of outages, a 10% rate increase with half the outages, or retention of present rates and reliability levels. Although the commercial and industrial customers surveyed had previously emphasized the need for lower rates, they generally chose greater reliability, implying a strong sensitivity to the cost of outage. Residential customers, however, clearly accepted lower reliability in return for lower rates.



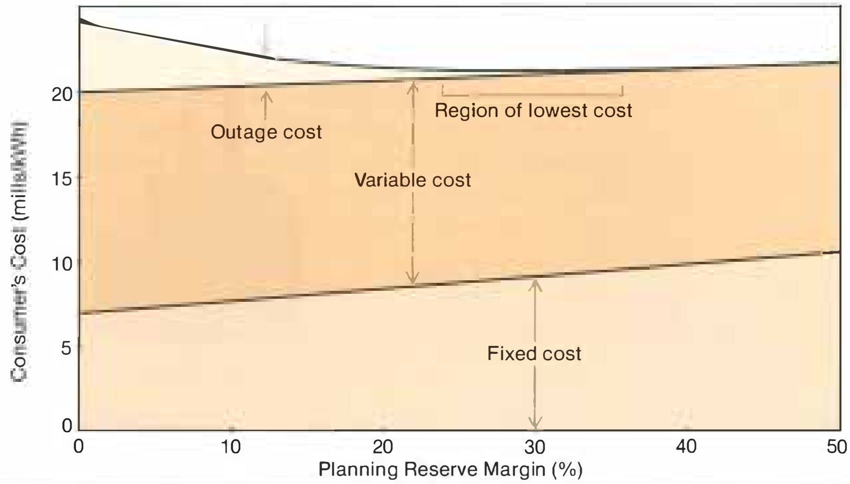
ment of electricity, for example, people may first cut back severely on air conditioning and next reduce electricity use for water heating and miscellaneous loads, but attempt to maintain refrigeration virtually unchanged, even when total electricity usage is cut by 75%. To investigate the information on perceived values that utilities may need when trying to determine curtailment strategies, adequate reserve margins, and acceptable prices for various levels of reliability, EPRI has sponsored a scoping study on value-based planning, for which a final report has just been published. The report was prepared by Levy Associates of Sacramento, California, and Meta Systems of Arlington, Virginia.

A problem with previous research in this area, according to the report, is that it has failed "to present the customer with clear trade-offs that examine the relationship between service cost and service levels." As a result, some demand-side management programs based on special rates for specific levels of service curtailment have failed to attract participation by the required number or kind of customers. A program to reduce air conditioner use, for example, may not sufficiently take into account the higher value that some large users place on this application. "Consequently, high users either don't participate or become the first to discontinue their participation. The result is a program populated by marginal participants that cannot possibly produce cost-effective results," the report concludes.

A recent survey conducted for Pacific Gas and Electric Co. is cited by the report as an example of how customers say they would respond when presented an explicit trade-off between electricity cost and reliability. The trade-off was offered as a choice among three options: a 10% reduction in electric rates in return for double the number of outages, a 10% rate increase with half the number of outages, and reten-

Capacity and Reliability

The highest level of reliability a utility can offer its customers depends largely on how much reserve generating capacity can be brought on-line to avoid interruptions. If the reserve margin is too low, reliability declines and outage costs rise sharply. Building new generating plants improves system reliability but adds capital costs that rise steadily with the increasing reserve margin. This case, taken from an EPRI report on the costs and benefits of over- and undercapacity, indicate that customers of the utility studied enjoy the least cost when reserves used in planning account for about 30% of total demand. The optimal reserve margin can be reduced if outage costs are lowered.



Innovative Marketing

The first step a utility can take to increase reliability without adding new generating capacity is to improve load factors by offering customers innovative rates. A recent EPRI survey shows that a large majority of utilities now offer such rates. The time-of-use rate is the most frequently chosen option for all three major classes of service—residential, commercial, and industrial. The interruptible-curtailable rate is second in popularity among commercial and industrial customers. Often the special-purpose incentive rate for residential customers involves an interruption or curtailment of service to a specific piece of equipment, such as a home air conditioner.

	Investor-Owned Utilities		Public Utilities	
Rate Type	Percent Offering Program	Number of Customers in Program	Percent Offering Program	Number of Customers in Program
Time-of-use (higher price during hours of peak demand)	69	244,665	57	6,890
Interruptible-curtailable (load interrupted or curtailed to a predetermined level)	56	104,073	46	7,452
Special-purpose incentive (reduced price for participation in a specific conservation program)	24	602,481	23	68,195
Inverted block (price increases with level of usage)	17	15,954,651	20	2,661,765
Residential demand (explicit demand charge [$/kW] in addition to energy charge [$/kWh])	9	56,620	26	2,288
Low-income residential (discount provided for low-income customers)	7	66,628	14	118,157
Demand subscription (customer contracts for a predetermined maximum demand level)	2	2,280	3	3

tion of present rates and reliability of service.

The results of the survey varied greatly according to the type of customer. About 70% of residential customers chose to decrease their monthly electric bill and accept lower reliability. Only 10% chose higher rates and reliability levels and the remaining 20% preferred to retain their present service. Commercial and industrial customers, however, overwhelmingly preferred the higher reliability option with its higher cost, even though these same customers had emphasized the need for lower rates on previous company surveys. The EPRI report concludes that this preference for higher reliability reflects a strong sensitivity to the cost of outages and helps explain why the utility's previous demand-side management programs have attracted more residential than business participants.

Such findings can have a profound influence on both demand-side and supply-side planning in an era of tight capital and strained reliability. The traditional rule of thumb for adding capacity has been to aim for a generation-related loss-of-load probability of approximately 1 day in 10 years. The advent of new, microprocessor-based communications and control technology, however, will enable utilities to provide varying degrees of reliability to different customers or to different end uses at customer locations and thus delay capacity expansion.

Similarly, demand-side management objectives have usually been proposed to avoid shortfalls when projected demand exceeds available capacity. New marketing strategies based on customer preferences regarding reliability may give utilities far more flexibility in managing demand and competing with other sources of energy.

The EPRI report concludes that the concept of perceived value of service can be used to create a more consistent link between the supply-side and demand-side planning processes. "The result would be an integrated approach to utility planning that uses customer needs and preferences as the principal planning criteria." EPRI's Energy Management and Utilization Division is considering a portfolio of research to assist utilities in implementing value-based planning.

Innovative rate design

Many utilities are already attempting to improve load factors and reduce the need for added capacity by experimenting with new rate structures. A recent survey of 158 utilities, prepared by Ebasco Business Consulting Co. of New York, showed that a large majority have implemented some form of innovative rates. The survey was jointly sponsored by EPRI, Edison Electric Institute, American Public Power Association, and National Rural Electric Cooperative Association.

About 70% of all the utilties responding to the survey offer at least one time-of-day rate, with participation in the program usually being voluntary. More than half the utilities also offer a special rate for industrial customers in which certain portions of their load may be curtailed. About one-quarter of the respondents offer residential customers a special-purpose incentive rate in which the operation of a specific piece of end-use equipment (such as a water heater or central air conditioner) is placed under utility control.

To help utilities better predict customer response to innovative rates, EPRI sponsored a study (conducted by Research Triangle Institute of Research Triangle Park, North Carolina) that focused on specific types of loads. After collection of data on energy costs and production processes of several industrial and commercial customers, a simulation model was demonstrated for two case studies involving major electricity users: cement and chlor-alkali plants. The model showed that for these two types of customers, long-term adaptation to various time-of-day rates could result in more than 50% reductions in peak kWh use and demand. For commercial customers, the study showed that thermal energy storage systems, which use electricity at night to chill water for air conditioning the next day, can provide an effective, load-leveling response to time-of-day rates.

"Both customers and utilities can benefit from new marketing efforts that involve varying levels of service," reports Clark Gellings, senior program manager, demand-side planning. "The key to success of these efforts is recognizing what the service needs of different customers are and how much those customers value reliability. As utilities begin to work more closely with various users to tailor service to specific needs, I believe we will see more satisfied consumers and a better image for the utility industry."

EPRI has undertaken a major new project to help utilities assess and plan new marketing efforts. A primary outcome of this project will be an understanding of utility customers' preferences and behavior in their purchase of electric energy.

Unbundling service

Beyond current marketing efforts that involve rate reductions determined implicitly by the value of reliability, new programs are being developed to offer customers more-explicit cost-reliability choices. Such programs involve the unbundling (separating) of electric service into discrete levels of reliability, with corresponding rates for each. Interruptions and curtailments may then occur more frequently for customers who save money by accepting a low priority level of service and less frequently for those who pay a premium for a higher priority level. Careful research will be needed, however, to ensure successful implementation of service unbundling.

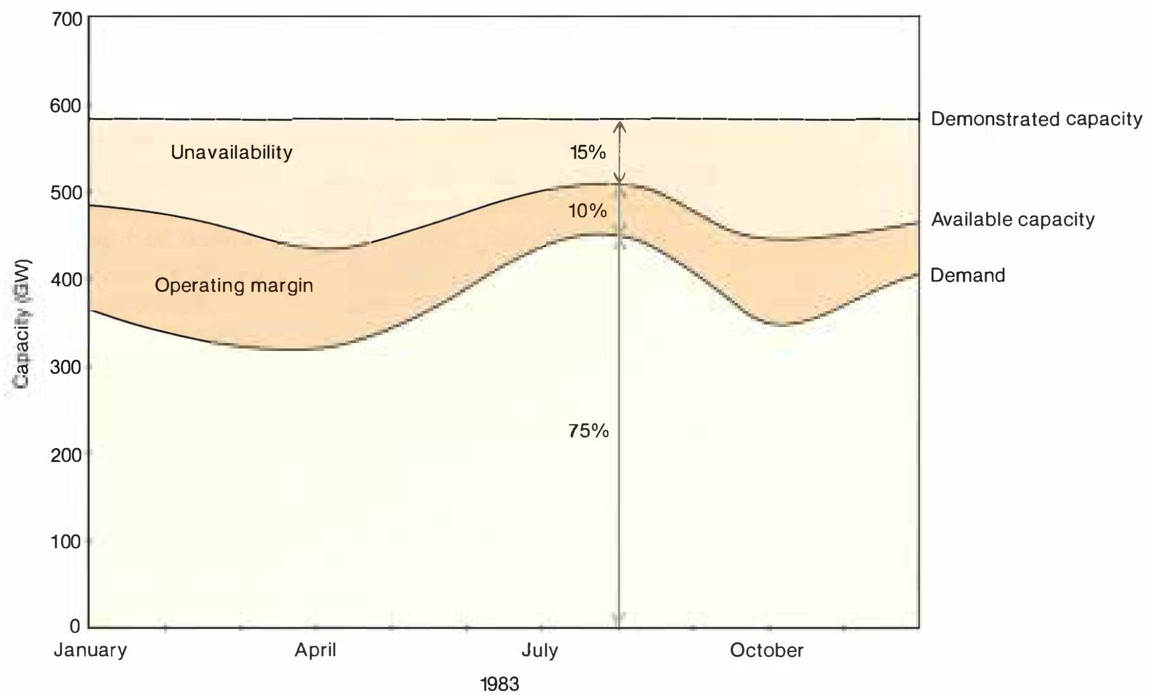
One ongoing research project has begun to elaborate some of the issues involved in unbundling and to analyze some of the practical problems that

Effect of Availability on Margins

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

U.S. Capacity and Operating Margins

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



must be overcome. The timing of this research largely reflects the recent development of sophisticated metering and control devices that are now becoming economical enough for mass use. (One of the chief hurdles facing earlier end-use management programs was the cost of remote-control devices to curtail service.) It may soon be feasible for even residential customers to purchase a special electric meter that allows partial curtailment of service while automatically providing the utility remote reading of billing information, all in return for lower electricity rates. The current project is exploring, in part, how utilities can prepare an acceptable menu of service priorities and rates for customers equipped with such new technologies.

What distinguishes the priority-of-service concept embodied in this research from earlier demand management initiatives is its breadth. Instead of curtailing power to specific customers or end uses in return for a special rate, this approach would present all customers with a menu of reliability levels and corresponding rates. Those choosing lower priority service would then allow a utility to exercise curtailment control over part of their regular load and would also expect that in case of a power shortage the utility would interrupt their electricity before that of a customer paying a higher rate. In turn, customers choosing greater reliability might be provided redundant circuits or other facilities, such as batteries or minigenerators. They might also be sold outage insurance to cover damages in the event of an interruption. Initially, prices would be assigned to different priority levels according to a utility's current generating constraints. Later, integrated planning of both supply and demand would enable priority charges to reflect the cost of adding enough new capacity to meet prevailing reliability requirements.

On the basis of information gathered in the current project, future research will be needed to develop a formal methodology that utilities can use in trying to implement service unbundling. EPRI has now issued an RFP for research to provide such a priority service methodology. The specific aims of this project are to develop methods and data for characterizing a priority service system and to develop the integrated analytic methods, information systems, and incentive mechanisms needed to plan and set up such a system.

"At a time when reliability is strained, utilities and their customers can both benefit from a rationing strategy based on individual preferences," comments Hung-Po Chao, project manager. "Previous studies have shown that many customers would be willing to accept different levels of service in exchange for lower utility bills. What is needed is a methodology to help devise an unbundling system that maximizes customer satisfaction."

Other challenges

Addressing the challenges to electric power reliability that lie ahead, however, will require more than scientific research. A variety of regulatory and energy security issues are also involved in determining the ultimate value of reliability. For the most part, work on these issues lies beyond EPRI's charter, although the information derived from the Institute's research may help the decision makers who must consider them. The importance of these issues to the future of the electric utility industry has been summarized in NERC's recent *1985 Reliability Review.* "Interruptions to customer service in the future will test customers' acceptance of the risks now being taken by some utilities. The Electric Reliability Council is concerned that if our regulatory, economic, and national security policies do not reflect an increased awareness of the need for adequate future electric supplies, the specter of unreliable electric service may become a reality."

In response, EPRI hopes that the research it is undertaking on value-based planning and service unbundling can help the nation cope more efficiently with whatever the future capacity situation may turn out to be. ■

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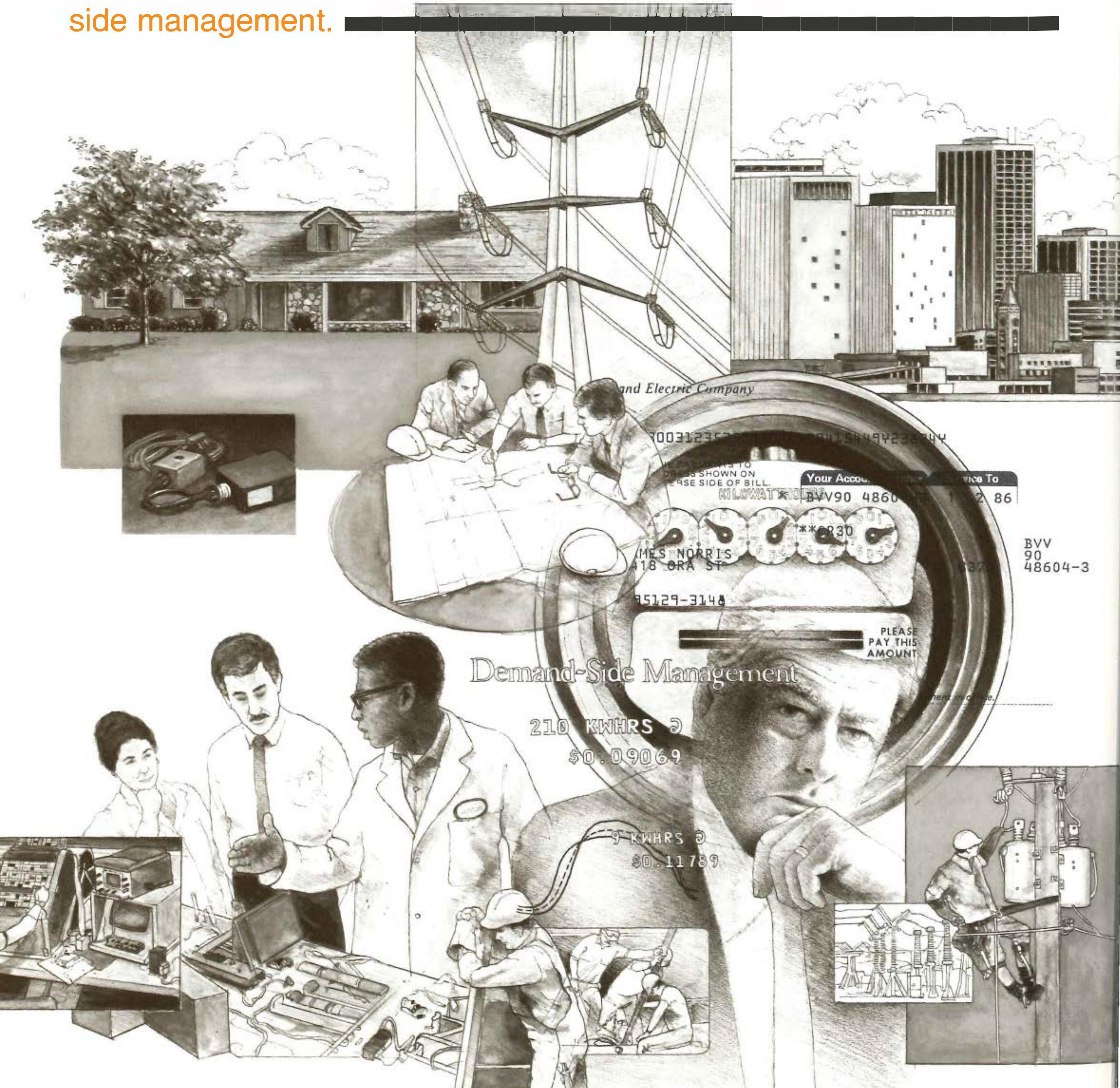
This article was written by John Douglas, science writer. Technical background information was provided by Clark Gellings, Energy Management and Utilization Division, and Stephen Peck, Hung-Po Chao, and Paolo Ricci, Energy Analysis and Environment Division.

by Brent Barker

NEW FORCES IN THE UTILITY MARKETPLACE

The revival of utility marketing and the quickening pace of new competition were explored in an EPRI Advisory Council seminar on demand-side management.



The golden era was brighter and ended more abruptly for Florida Power & Light Co. than for most other electric utilities. Throughout the 1950s and 1960s it was all FP&L could do to keep up with electric sales that were booming along at 14% per year. Plants were built in rapid succession, and the diversification away from oil was in full swing. It was a glorious time financially for FP&L—for every dollar of interest expense going out, it had five of revenue coming in—and it briefly became one of Wall Street's darlings.

Then in 1970, three years before the oil embargo, the bubble burst for FP&L. Its construction schedule slipped, demand for power surged ahead of capacity, and periodic brownouts rolled through the FP&L service territory. Joseph Collier, vice president for marketing and energy management at FP&L, recalls that "at that time it all came to a screeching halt. We began a major cost-cutting campaign, cutting out all the frills. And one of the frills we got rid of in 1970 was the Sales and Promotion Department. We were one of the first in the nation to totally discontinue promotional activities, a decision we later came to regret."

Collier recalls that the brownout riveted his company's attention on rebuilding its reserve margin because the company was convinced that reliability was what the customers wanted and needed the most. "But we were only half right," he said. "Price had become a definite problem. By the late 1970s things were building up to an intolerable situation, and we became convinced that not all the answers to utility economics lay on the supply side. In 1978 we created the Marketing and Energy Conservation Department, and I now find it ironic that the renewal of marketing at FP&L was born out of the necessity to *unsell* electricity."

As with FP&L, marketing has come full circle for many utilities in the last dozen years. It's back but not universally so, and almost never in the same form. The marketing revival carries with it a new sophistication that allows the seeming contradiction of both selling and unselling at the same time. To some utilities and public utility commissions, marketing remains an anathema, sparking fear of new plant construction that would drive up prices for existing customers. To others, particularly the new utility marketers, the concept has evolved into a broad, versatile set of activities intended to bring the demand side into strategic balance with supply in such a way as to reduce the average cost of electricity. Yet central to all these themes is a renewed appreciation and concern for the utility customer.

Many utilities are feeling the need to forge new relationships with their customers as a means of controlling costs and preparing for the future. Some lost touch with major customers during the tumultuous 1970s, and enough competitive forces have since arisen, within and without the utility industry, that large blocks of utility business can no longer be taken for granted. Demand-side management (DSM) programs are being rapidly adopted by all manner and size of utilities so they can not only predict demand, but also better control it, serve it, understand it, hold onto it, compete for it, and provide it with a new array of service and product options. Intuitively there is the sense that the changes ahead are going to be every bit as great as the changes behind and that the electric utility industry is at the threshold of a new competitive environment in which service is going to be as much a key to the market as price.

It was in this context that the EPRI Advisory Council invited 60 participants from utilities, industry, government, and universities to explore "Demand-Side Management in the Electric Utility Industry." At the Newporter Hotel in Newport Beach, California, 10 invited speakers led off three days of vigorous exchange that began with current utility DSM experience and then opened into a broader discussion of the portent of new forms of competition entering the utility arena.

Bridge to the future

There was consensus that the forces of change were coming more swiftly than anyone had anticipated a few years ago and that the benefits of DSM—from deferring new plant construction to improving the efficiency of the energy system to better customer service—were sufficiently large to encourage utilities to step more aggressively across the meter and join with their customers in reshaping the patterns of electricity use.

No one was opposed to DSM; from all points of view it seemed to be the right thing at the right time. Rather, the real concerns about DSM focused on how, how much, and how fast. There was tacit agreement that DSM was here to stay, representing the latest stage in the natural evolution from load management and conservation activities of the 1960s and 1970s and providing a natural transition to the future of utility marketing.

One of the hallmarks of DSM as a marketing tool is providing an expanding array of options for utility and consumer alike—options that give utilities new flexibility, options that empower consumers with choice, options that set the stage for a fundamental shift from a commodity-oriented business to a service-oriented business. Clark Gellings, senior program manager at EPRI, pointed out that currently there are at least 150 specific types of DSM options utilities can use to alter patterns of demand, resulting in load shapes of economic advantage to both utilities and customers. These he categorized into a definitive framework for DSM according to six basic load shape objectives.

- Clipping the peak by such means as direct control of appliances (There are now about 1.5 million points being directly controlled in the United States.)
- Shifting the load on a daily or seasonal basis by storage technologies on both sides of the meter
- Filling the valleys by building off-peak load
- Reducing demand through strategic conservation programs
- Building load in strategically targeted

areas, typically those with the potential for reducing average costs

□ Creating a flexible load shape through subscription programs that curtail electricity use during critical periods

Gellings summarized the national drive toward DSM by saying, "The composite effect of U.S. utility DSM activity will be to reduce demand growth about 55 GW by the year 2000. That's about 8–10% of projected consumer demand, a very significant amount."

Direct utility experience with DSM varies from utility to utility, but the forum provided a collective glimpse into current practice. "It buys us time," said Stephen Reynolds, vice president for rates at Pacific Gas and Electric Co., "minimizing costly long-term expansion. And it's a significant element in the battle to keep our customers healthy and happy. We spend about $150–$180 million per year on conservation and load management activities."

John Bryson, executive vice president, Southern California Edison Co., noted that SCE's plan calls for nearly doubling the 620 MW of load management in place in the next decade. But William Eglinton, senior vice president for operations at Public Service Co. of New Mexico, implied a more radical departure from current practice. "Our vision of DSM is very different than valley filling and peak shaving. Our survival is at stake, and we are going to have to be doing things that have never been done before."

Most participants viewed the real long-term benefit of DSM in terms of creating stronger ties between utilities and their customers. Sherwood Smith, chairman, president, and CEO of Carolina Power & Light Co., said, "We've been at this for over five years and the advantage is that it allows us to meet our customers on an individual basis. Whatever we do, we do *after* listening to our customers."

Collier of FP&L added that "it's a good way to get control over our destiny, to avoid rate cases, emphasize value and efficiency, reawaken the pride of our employees, and meet our customers face to

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Gellings

face. We've saved about 200 MW of capacity with DSM. But most important, it has helped us recognize that our product is really service, comfort, convenience, not just kilowatthours."

Several speakers emphasized that utilities are no longer selling a homogeneous product and that as the perception of "different colors of kilowatthours" takes root, creative marketing can begin. Robert Uhler, vice president of National Economic Research Associates, pointed out that differentiating the utility product by time of day as well as by the terms and conditions of sale (for example, firm or interruptible power) is the first step toward the "unbundling" of prices and

"We've saved about 200 MW of capacity with DSM. But most important, it has helped us recognize that our product is really service, comfort, convenience—not just kilowatthours."

Collier

services. And this in turn allows market segmentation and targeted selling to shift the load around to minimize cost.

"If you are talking marketing," explained Uhler, "you're essentially focusing first on the customer and second on your production decisions. That's the way most businesses are run. It returns your emphasis where it rightly belongs, and that's on the customer. And in that scrutiny of your customers you are going to discover who are your price-sensitive customers and who are your service-sensitive customers."

Uhler, who spent several years as executive director of the Electric Utility Rate Design Study, went on to say that "pricing is more than just looking at costs. In this industry there is a tendency to have your accountants look at costs and translate those mechanically into rates. I think you have to be much more creative and design rates with price sensitivity, price elasticity, and perceived value in mind. This is, of course, now going on; I can cite examples from all across the country of utilities giving price discounts—in a few instances, up to 40% for industrial customers."

Hamp Baker, chairman of the Oklahoma Corporation Commission, agreed that "price is the key. The economics are now so tight and foreign competition so keen that customers will respond to utility incentives. Anytime we can shave the demand and cut the cost, we're making money for utility customers, for the ratepayers of our state, and for the nation."

Despite the potential it appears to have for restoring the competitive position of both utility and customer, much of the enthusiasm for DSM at the seminar was eclipsed by concerns over the long-term direction of the industry and the role DSM plays in the larger picture. Just how far can DSM go? Are the saturation limits apparent? Does it reduce uncertainty surrounding future demand? Does it, in fact, significantly defer the need for new supply? Several viewed DSM as perhaps holding forth the illusion of a panacea to supply-side problems, including excess capacity in many parts of the industry, regional imbalances in capacity, and the near moratorium on central station construction. Others viewed the current hiatus in construction more optimistically, as a window for planning, for experimentation with DSM, and for development of new systems, relationships, and attitudes.

"I think you have to be much more creative and design rates with price sensitivity, price elasticity, and perceived value in mind. This is, of course, going on. All across the country, utilities are giving price discounts."

Uhler

Capacity debate

Whatever breathing room is available for the present, many were convinced that the larger problem is balancing supply and demand for the coming decades. Chauncey Starr, vice chairman of EPRI, lobbed the first volley in the capacity debate. "Population will grow 30% in the next 20 years," he predicted, "and with it will come economic growth and further electrification. Today's capacity margins will disappear in 5, 10, 15 years. *When* we don't know, but it's inevitable that construction will take place, and all new construction will cost more than online capacity." And Kenneth A. Randall, chairman of ICL, Inc., and vice chairman of Northeast Bancorp, turned up the heat when he added, "The larger problem is the convergence of forces once we have flattened the utility demand cycles and run out of capacity. Suddenly we will face a crash program of construction that could lead to a crunch greater than the first two OPEC shocks. We need orderly planning to bring on baseload for the longer term."

Discussion ensued about the probability of a shortfall in the 1990s and about the gap between high and low forecasts of future demand—visually presented as a wedge opening outward into the future and dubbed by the participants as the jaws of uncertainty. Some spoke of the need for more capacity as a form of national insurance and some argued that the cost of oversupply was far less than the cost of undersupply. Still others rejoined this line of reasoning by saying the United States could no longer afford the idea of building more just to ensure there was plenty to go around. They pointed to what they believe are more cost-effective routes, including conservation, wheeling, cogeneration, and importation from Canada.

Andrew Varley, chairman of the Iowa Commerce Commission, picked up on Randall's point of mobilization. "A crash program is not necessarily bad," he countered. "The old idea that you can take 10–15 years to build a plant just is not tolerable any more. Can you imagine any other business taking 13 years to install a major production facility? Why, the interest alone will kill you. Proper planning rejects the idea of bringing on huge segments for a market that can't support it."

"Price is the key. The economics are now so tight and foreign competition so keen that customers will respond to utility incentives. Anytime we can cut the cost, we're making money for the customer."

Baker

The United States, many agreed, had ensnarled itself in a web of licensing, siting, and regulatory entanglements that have stretched construction times beyond reason. Floyd Culler, president of EPRI, pointed out that United States–designed plants are being built in Japan and Taiwan in five years and went on to describe the thrust of EPRI's R&D program to develop alternatives "to reduce the time and cost of nuclear baseload plants by studying modular and standardized designs. We are also investigating the economics of smaller units that require less capital and involve less risk than today's large baseload plants. Smaller units will allow utilities to 'crawl up the demand curve.' "

Others pointed out that meeting capacity needs with small plants would be an anomaly in the world. "In Canada the massive economies of scale are still in existence," said Edward Burke, chairman of the Rhode Island Public Utility Commission. "And we in the border areas have to take maximum advantage of them." He was referring to the provocative issue of interregional power transfers, which cropped up time and again at the seminar, often linked to the vast hydroelectric potential of Canada. "But when we in New England bring up Canada," he continued, "we are told 'Canada is a foreign power, there are reliability problems, and the transmission system is inadequate.' Well, I say that Canada is the best ally we have, and since there are 100,000 MW of untapped, low-cost power up there, we have to start grappling with reality."

John Driscoll, commissioner, Montana Public Service Commission, agreed that Canadian power must be considered in any appraisal of future capacity. "But how we tap that power or the power of any area of surplus is the real issue. To my mind the biggest long-term problem is transmission, not baseload construction. Right now we don't have the economic signals in place to move power from where it's not needed to where it is needed."

The participants were reminded by Smith that power transfers in the United States have increased dramatically over the past 10 years—as much as 50%—and, despite major engineering and technical obstacles, will continue to grow rapidly. "It's in the national interest to promote interregional transfer," he said. "I know very few in the U.S. electric utility industry planning to build large baseload plants."

"These power transfers," said Ralph Cavanagh, attorney for the Natural Resources Defense Council, "are a major new variable in the supply picture." He noted that at least 9 Canadian provinces are trying to negotiate long-term supply contracts and that California is now reviewing the prospect of power transfers from 10 states and 2 Canadian provinces. "This would have been unheard of just a few years ago. Yet I see in none of this a panacea for U.S. capacity needs in the long term."

The answer from Cavanagh's point of view resides in the conservation resource potential, and his prescription for the utility industry is to "stop complaining about uncertainty and do something about it—to narrow the menacing 'jaws of uncertainty' by actively shaping electric demand. Taking advantage of, first, the remarkable breakthroughs in the efficiency of end-use devices and, second, the current mechanisms for reliably and predictably delivering conservation, the industry is now in a position to reduce costly uncertainty about future demand. If investment and regulatory policy can fix the average electricity needs of houses, appliances, and commercial buildings at levels far below those of existing stock, demand—even in the face of population growth—can be reduced. Also, forecasting errors concerning future growth in the building and appliance stock became much less damaging."

Some took exception to Cavanagh's suggestion of an unlimited scale to the conservation resource, others to his advocacy of appliance standards. "The facts don't support the importance of what you are talking about," said Starr. "Our study shows conservation could save 34% of total energy if we disregard capital cost and 17% if we take cost into consideration. We have already achieved about 8% since 1975, so there's about 10–15% left—a very small fraction of the 'jaws.' Your argument is not wrong in detail but just a very small part of the total picture."

Cavanagh responded by saying, "Please don't base your assumptions on a 10-year-old study. The rate of change in conservation technology is both astonishing and encouraging, particularly since 1983. I think the magnitude of the conservation potential is substantially greater than anyone here concedes. The notion that the conservation resource will be exhausted in the near term or that it can only marginally affect the need for new capacity should be thoroughly reexamined."

'It's in the national interest to promote interregional transfer of power. I know very few in the U.S. electric utility industry planning to build large power plants.'

Smith

'The utility industry should stop complaining about uncertainty and do something about it—to narrow the menacing 'jaws of uncertainty' by actively shaping electric demand.'

Cavanagh

Smith took the floor to say that "conservation does have unexploited potential, and it's important, as Ralph Cavanagh says, to continue to mine it vigorously. I'm sure, however, it can't do the whole job." Smith went on to describe the implications of not meeting demand, saying that in general the consequences of undersupply are far greater than those of oversupply because of the paralyzing effect it can have on all parts of the economy. He drew analogies from water shortages in the Northwest and coal strikes in the United Kingdom, and he cited a study showing that a 15-minute outage at a pulp and paper mill would cost $50,000, or $4.40/kWh.

René Malès, vice president, Energy Analysis and Environment Division at EPRI, elaborated on Smith's point. "On the basis of extensive studies of outage costs—work paralleled by studies in Sweden and Canada—the consensus is that on average worldwide, an unexpected outage will cost somewhere above $3/kWh. For some classes of service, such as residential, a short outage may be much less costly. But for others, such as an aluminum plant that freezes up, it could run as much as $30–$100/kWh."

The argument for avoiding undersupply situations clearly did not sit well with some participants concerned with the new competitive environment facing the utility industry. "The cost of not having adequate capacity I'm sure can be quite large," said Varley, "but what about the cost of having excess capacity that drives your rates so high that your industrials leave your service territory? Those are very real costs to you and to your consumers, costs that can cripple your economy as surely as outages."

The new competitive environment

The full implications of the rapid runup in electricity costs during the 1970s are still unfolding, but they have already set the stage for a new competitive environment that foreshadows sweeping change in the utility industry. Competition on the supply side extends from alternative fuels to independent power producers to industrial cogenerators to utilities in the United States and Canada with surplus power. On the customer's side, fierce international competition is becoming a greater and greater factor. ''France can build nuclear power plants for 25% of what we do,'' said Randall. ''This is indicative. Unless we can provide reliable power at low cost, we are going to lose our industry to foreign competition.''

Douglas Bauer, senior vice president for strategic planning, Edison Electric Institute, extended Randall's point. ''The competitive world that we are now firmly implanted in is not just the familiar one of one fuel against another, but now one company against another and, increasingly, one utility against another. And it's international as well as national. John Williamson, CEO of Toledo Edison Co., said he now considered himself 'head to head with Tokyo Electric' and that's the way he is now configuring his business.''

Philip Schmidt, professor of mechanical engineering at the University of Texas, added that ''the Canadians are selling more than power these days. Ontario Hydro and Hydro Quebec are very aggressively courting the exportation of American industry to their service territories.''

Several people mentioned that cost is forcing large industrial customers to take matters into their own hands. Kenneth Hollister, of W. H. Reaves & Co., reported that ''aluminum plants in the Northwest are telling utilities to provide cheaper power or the plants will close; two in Kentucky have already closed. Bethlehem Steel is trying to break the franchise with Northern Indiana Public Service Co. because they can buy from Commonwealth Edison for 50% less. And Dow Chemical is now a major supplier of cogenerated electricity to Texas Utilities. What this shows is that these customers have clout, and increasingly are in a position to tell utilities what, when, and how much. To my mind *that*—not what utilities are doing—is demand-side management.''

‘These industrial customers have clout and increasingly are in a position to tell utilities what, when, and how much. To my mind *that*—not what utilities are doing—is demand-side management.’

Hollister

Hollister also pointed out some new entrants to supply-side competition that bear watching. ''There are 2000 MW of unregulated capacity going into Nevada that may be a harbinger. And there may be great bargains out there in abandoned nuclear plants; Eastern Utility Associates, for example, just bought a portion of Seabrook at 14¢ on the dollar.''

Utility response to the new competition varies dramatically. Most are accelerating DSM programs and revitalizing their marketing forces. But perhaps none has broken ranks with tradition faster and approached the new world with more sense of adventure than Public Service of New Mexico. ''We are in an unprecedented transformation as an industry,'' said Eglinton, ''and for our part we are casting our eyes fondly toward the entrepreneurial, less-regulated world. Our new strategies have to recognize that the demand for our goods is more elastic than we thought. We're seeing more substitute goods than we thought, much of it from the unregulated world. We as an industry better start recognizing that our customers can go elsewhere. As Peter Drucker says, 'the biggest problem in times of turbulence is to act with yesterday's logic.' ''

‘Look at the growing nimbleness with which our industrial customers can get in and out of the business of cogeneration. For the later 1980s, competition is clearly the name of the game for electricity pricing.’

Reynolds

The strategy being pursued by Public Service is two-fold. ''First, we'll consolidate and secure existing markets by increasing the nature and quality of service, preventing market-share leakage, and erecting market entry and exit barriers. Second, we'll enter new markets, diversify into new product lines, enter new business configurations, and possibly open the door to selling into the interstate power market. We're working with local industry to help it expand and trying to lure new industry into the state.''

Many participants focused on the potential instability of the industrial load and called for new efforts to bring more innovative and active marketing into play. Failure to do so, in the mind of Bauer, would beg the question of ''whether we will have an industrial base at all, or whether we will be faced in 10 or 15 years with the dreary task of serving only our residential customers.''

Reynolds noted the ''growing nimbleness with which our industrial customers can get in and out of the business of cogeneration. For the later 1980s, competition is clearly the name of the game for electricity pricing. Our industrial customers are freely able to provide their own electricity, often at less than our average cost.''

Schmidt strongly urged utilities to begin to reestablish communications with their industrial customers and reinstate technical expertise in the consuming industries not unlike that of the arc-furnace expert employed by utilities in the 1950s and 1960s. Pointing to the potential of modern electrotechnologies, he said, "Utilities must realize they are in a unique position to catalyze increased productivity in the industrial sector."

"Utilities can assist their industrial customers by helping them move toward new processes that are inherently energy-efficient," suggested Richard Rowberg, program manager for energy and materials at the Office of Technology Assessment. "This is the long-term view. Just as in the environmental area, the first reaction was to clean up the waste stream; over time and with more capital we moved to inherently clean processes. With energy, again the first reaction was to cut back, to add capital to old equipment to save energy. But now to the extent we invest capital in the conservation of old equipment, the more we defer opportunities to move into new energy-efficient processes." Collier brought home Rowberg's point by saying that the marketing strategy at FP&L now includes talking to new and different people, those responsible for the capital budgets as well as those responsible for energy budgets.

Several participants even suggested that utilities may want to join with their customers in mutually compatible business enterprises, or diversify into services of benefit to their customers' business. But all these efforts to branch out, diversify, spin off, and reformulate seem to be symptomatic of a general loosening of the bonds of traditional regulation. Whether the competitive forces now building up in the electric utility industry will inevitably lead to deregulation was a question that seemed to hover in the background of the seminar for days. Bryson of SCE finally brought it to the forefront.

The specter of deregulation

"The largest question in the electric utility industry is deregulation," said Bryson. "What concerns me is that these changes could be put into place with relatively limited exploration of the large social, political, and public policy consequences."

"We are in an unprecedented transformation as an industry, and for our part we are casting our eyes fondly toward the entrepreneurial, less-regulated world."

Eglington

The speed of imminent change being brought on by competition seemed to have caught everyone by surprise. Driscoll said, "I've been in regulation for five years and things that were predilections when I started are ancient history now. And everything we're talking about could well take place in the next five. After years of hearing such cases, I'm coming to the conclusion that the true avoided cost is really the market price; with that I think we are moving conceptually very rapidly to a whole new way of moving energy around the country. I think when surplus capacity is exhausted, utilities won't even be in that business anymore unless they have a wholly owned generating subsidiary."

"The largest question in the electric utility industry is deregulation. What concerns me is that these changes could be put into place with relatively limited exploration of the large social, political, and public policy consequences."

Bryson

Deregulation would bring with it sweeping and possibly unintended consequences. This was the speculation of Bryson, who spent four years as president of the California Public Utilities Commission. "I don't pretend to have a full grasp of what the consequences of rapid deregulation would be, but let me throw out a few observations based on what has happened in airlines, telephone, trucking, and so on.

"First, there would most likely be intense new efforts to slash costs. We've seen that in airlines where wages have been reduced repeatedly, and layoffs have become common. Second, you would tend to get greater risk aversion, at least with respect to major investment. While deregulation might bring some fresh blood and new ideas, at a higher level of technology these would most likely be greater aversion to risk. Third, you would have a greater short-term focus—people looking to recover costs in three or four years. In a deregulated environment, electricity providers would face a lot of uncertainty. One way to control risk would be to develop strategies to limit the term of risk.

"Fourth, I would expect less-reliable service margins. The stability and cost recovery provisions of traditional regulation have contributed to a system in which reliability was encouraged and supported. Fifth, customers with substantial market power tend to do better in a deregulated market and customers with limited market power, on the whole, do worse. The market would tilt toward higher rates for residential and small commercial customers. And sixth, among utilities I would expect less information sharing, less cooperation, and for better or worse, less sensitivity to public policy social directives.

"I would hope for debate on these points, and others. But if you look at what's happened over the last 5 to 10 years in other regulated industries, and look at the speed with which substantial

Speakers

Hamp Baker, Chairman
Oklahoma Corporation Commission

John E. Bryson, Senior Vice President
Southern California Edison Co.

Ralph Cavanagh, Attorney
Natural Resources Defense Council

Joseph Collier, Vice President
Energy Management
Florida Power & Light Co.

William M. Eglinton, Vice President
Planning and Regulation
Public Service Co. of New Mexico

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Richard F. Walker, President
Public Service Co. of Colorado

Alvin M. Weinberg, Director
Institute of Energy Analysis
Oak Ridge Associated Universities

David C. White,* Director
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Massachusetts Institute of Technology

Dean G. Wilson,* Executive Vice President
Operations and Engineering
Lone Star Steel Co.

Herbert F. Woodson,* Director
Center for Energy Studies
University of Texas

Richard Zeren, Director
Planning and Evaluation, EPRI

Orin Zimmerman, Technical Director
Energy Utilization, EPRI

*Member of Advisory Council.

deregulation has taken place in the natural gas industry over the last 2 or 3 years, that kind of change could well come very, very soon—and without a lot of debate about whether these things are good or bad for the country."

Varley had a similar foreboding about stepping blindly into deregulation. "I'm fearful that in times of excess capacity regulators or legislators may be tempted to walk away from their responsibility by simply declaring the whole thing competitive. We may be on the verge of setting national policy by assuming there are elements of a market in existence that really aren't there. Just the fact that the physical facilities may not exist to transfer power from producer to consumer can create aberrations.

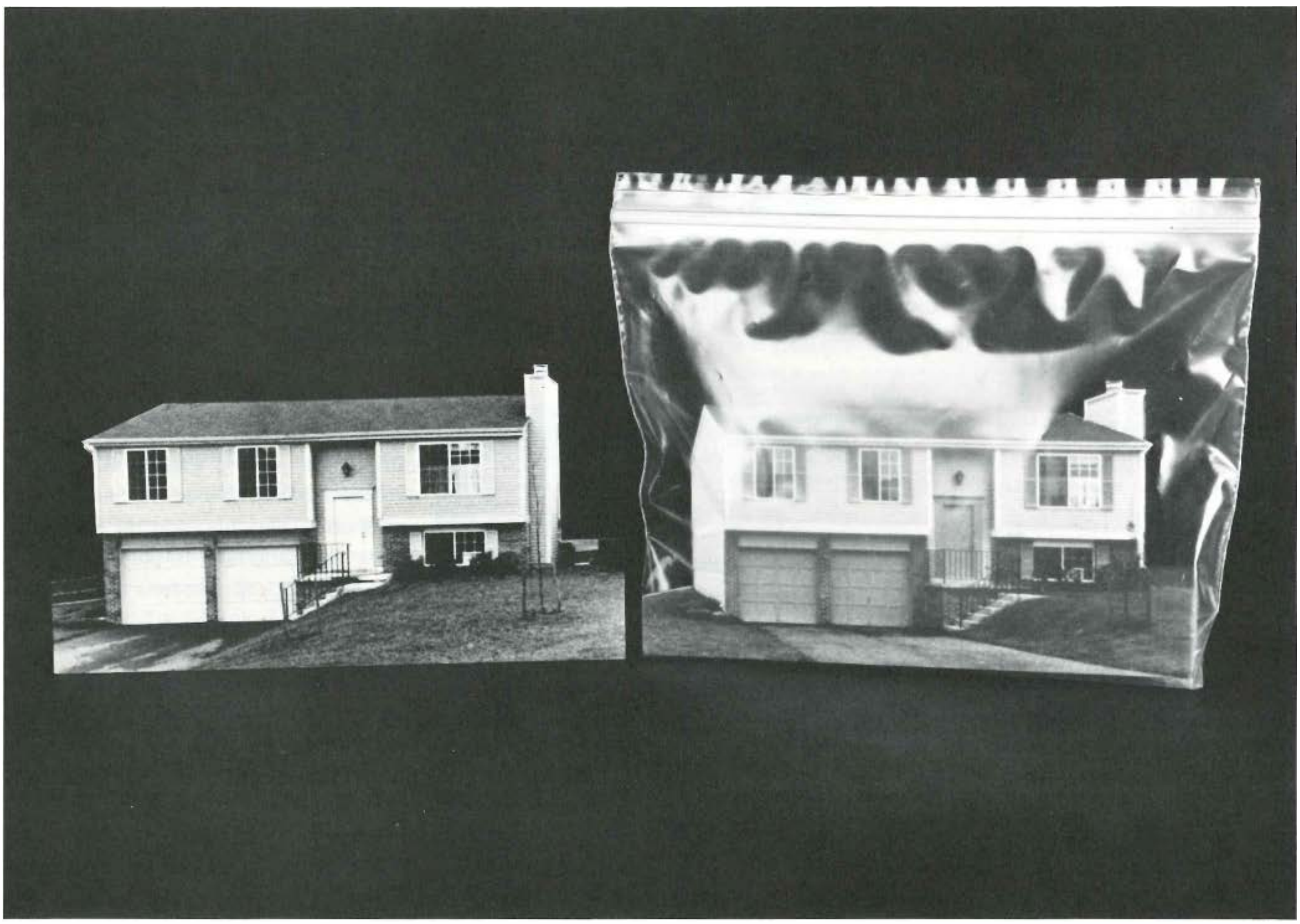
"I'm sure the prospect of solving the problem through a competitive market would change dramatically in times of shortage. With shortage there could be such extreme fluctuations in price and such extreme conditions of preference for those with market clout that we as a nation would find it so unacceptable that there would be a strong move for nationalization."

As the seminar drew to a close, it was clear that the forces of competition sweeping the industry would transform and redefine the relationships between utility and customer implicit in the term *demand-side management.* It was also clear that the role of a cooperatively sponsored R&D organization such as EPRI would be both enlarged and diminished. "The competition among utilities themselves as they pursue new markets poses an enormous dilemma for EPRI," said Bauer, "namely, how to partition which research is appropriate for a central R&D organization and which is appropriate for a specific company."

Regardless of how the Institute is changed by the push and pull of a newly competitive environment, one thing is certain—to support the industry in these changing times, EPRI will be taking an even closer look at the customer as an interactive part of how the utilities do business. ■

THE DYNAMICS OF INDOOR AIR QUALITY

Home energy conservation measures that reduce air exchange rates have raised concerns that harmful levels of pollutants could accumulate indoors. New research suggests that tight construction and good indoor air quality are compatible goals.



Awareness is growing that the air indoors, where most people spend 80–90% of their time, often holds more pollutants than the air outdoors. One avenue of pollutant removal from buildings is air flow—precisely the flow that weatherization measures aim to reduce. As a result, conservation programs that plug air leaks in buildings to save energy are now being questioned. The stakes are high. Air leakage accounts for perhaps one-third of the heat loss from residential buildings and wastes about 5% of the nation's total energy consumption every year. Given the potential savings, government, utilities, and homeowners have all supported home weatherization programs. Counteracting the known benefits, however, are the unknown health effects that rising indoor pollution levels might instigate.

How tight is too tight? Under what circumstances does energy-saving weatherization seriously compromise air quality? The quantitative information that utilities and others need for guidance in conducting conservation efforts is just beginning to emerge.

A benchmark study by Geomet Technologies, Inc., is developing data on the air quality effects of weatherizing a home. One effort under this study has been an experiment carefully designed to quantify the relationships between the three major variables that enter into the search for a satisfactory balance: air flow, energy use, and pollutant levels. An improved understanding of the physical processes in buildings will, in turn, point the way toward better control strategies.

The indoor setting

The air quality issue has moved indoors by stages. Outdoor standards set by the federal government in 1970 targeted the major precursors of urban smog, namely combustion products from auto exhaust and industrial stack emissions. The initial worry was that these pollutants could seep indoors. The realization soon followed that the indoors, with fuel-burning appliances and fireplaces, had combustion sources of its own. Identifying other pollutant problems that are specific to the indoor environment, such as radon, formaldehyde, and household chemicals, has been the third and most recent step.

Government response to indoor air quality problems has lagged far behind the effort outdoors. There are no overall federal standards specific to indoor air. Outdoor standards and industrial standards set by the Occupational Safety and Health Administration (OSHA) sometimes serve as a basis for guidelines in public buildings. Policing air quality in 85 million private homes is clearly not feasible, although better information could help the residents identify and manage any pollution problems that may occur.

Basic to indoor air quality research is the concept of air exchange between a building and its surrounding environment. A building's rate of air exchange is the number of times its full volume of air is replaced with outside air during a given period of time. As many as four air changes per hour (ac/h) have been measured in leaky older homes. Supertight homes can be built to achieve average rates as low as 0.1 ac/h. Rates can vary greatly from season to season, day to day, or even hour to hour, depending on weather conditions.

Air exchange occurs both intentionally and unintentionally. Deliberate air exchange, accomplished by opening windows or running exhaust fans, is termed ventilation. Uncontrolled leakage of air through cracks or other openings in a building's shell is called infiltration. The actual rate of infiltration is governed by wind pressure on the building and by temperature differences between indoor and outdoor air. Note that the terms *tightening* and *weatherization* as used here refer to measures that reduce air infiltration—caulking, weatherstripping, storm windows or doors—and not to insulation measures, which focus on reducing conductive heat loss.

Indoor pollutant concentrations depend both on source strength and on rate of removal. Because air exchange is a major means of removal, houses with significant indoor sources can experience pollutant buildup when tightening measures succeed in cutting the rate of air infiltration.

Common indoor pollutants may be classified into several types. An important health concern is radon, a naturally occurring radioactive gas that can become trapped indoors after emanating from the earth beneath the house or even from earth-derived building materials used in constructing it. Colorless and odorless, radon decays into highly unstable elements known as radon progeny, which attach readily to dust particles in the air and then deposit in the lung, where the alpha radiation they emit can cause cancer. Although exposure risks may not be adequately quantified, radon concentrations of more than a few picocuries per liter of air could be considered cause for concern. Many houses in Sweden have registered such levels, as have American homes in locations as diverse as Maine, Florida, and Montana.

Volatile chemicals make up a second class of indoor air pollutants. Formaldehyde is perhaps the best known. It occurs in synthetic building materials and in many household furnishings, including carpets and drapes. The pungent smell is a warning signal, but irritation can begin at exposure levels even below the odor threshold of 0.05–1.0 ppm. Although OSHA's eight-hour average standard for U.S. workers is 3 ppm, current recommendations target the range between 0.1 and 0.5 ppm as an upper limit for nonoccupational indoor exposure, consistent with the indoor formaldehyde standards now being established in some northern European nations.

Other chemical contaminants are also hard to avoid. The average American home harbors a number of aerosol cans containing chemical propellants, as well as paints, cleansers, insecticides, or other potential air pollutants. A recently completed five-year study by the Environmental Protection Agency (EPA) found that levels of some 20 volatile organic chemicals are typically much higher indoors than outdoors, sometimes 100 times higher.

Combustion products are the indoor pollutants that have been investigated most extensively because they were the first to be recognized. Measuring indoor levels from fuel-burning appliances and tobacco smoke is the current focus.

These common airborne pollutants, along with the pollutants shed by people and their pets, are the main types thought to be influenced by house-tightening measures. Asbestos and other mineral fibers are a special case that must be addressed separately because their concentrations and control are less dependent on air exchange.

Given the complex variables that operate simultaneously on indoor air, how do researchers get a grasp on air quality dynamics? One strategy is the mass balance approach, which considers a pollutant in terms of its sources and its sinks.

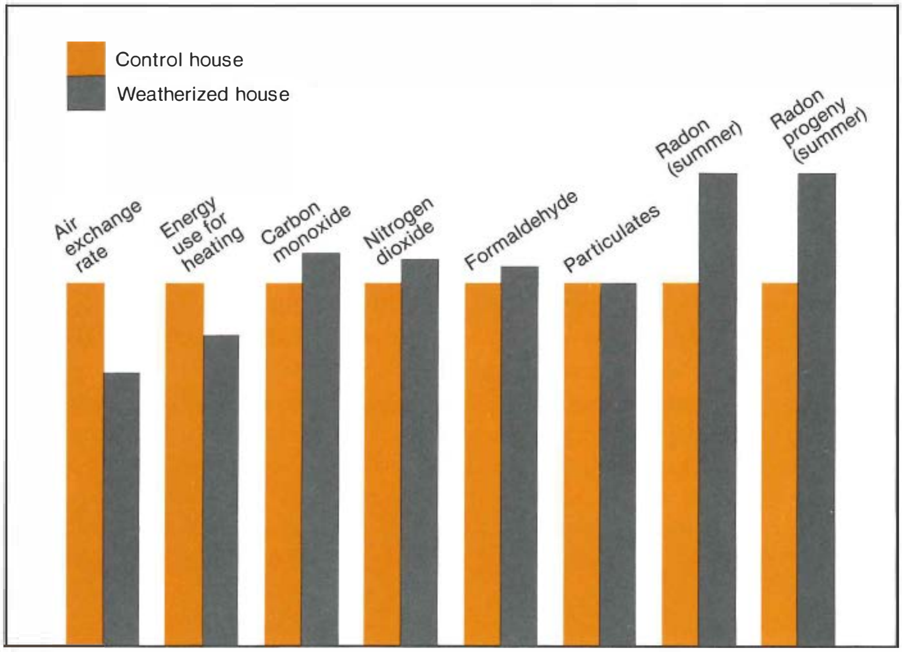
Four questions provide a framework. How much pollutant is coming in from outdoors? How much is going outdoors? How much is being generated indoors? And how much is being removed indoors, say, by filters, as opposed to being removed by expulsion to the air outside? The answers provide an estimated pollutant concentration for a specific time period. This mass balance approach is being used increasingly in current research, including the Geomet study that breaks new ground in quantifying the complex interactions that occur.

Quantifying the problem

The Geomet study used two identical, newly built houses to provide the data for this rigorously controlled experiment. Located side by side in a Maryland housing development, both were monitored for several weeks to establish baseline levels of energy use and air quality. One was weatherized and equipped with an air-to-air heat exchanger, whereas the other was not. Comparing the experi-

A Tale of Two Houses

EPRI and its contractor, Geomet Technologies, Inc., used two adjacent houses of identical design and construction to study the relationships between building tightness, energy consumption, and indoor air quality. One building was weatherized for tightness and equipped with an air-to-air heat exchanger, while the control house was kept in its original state of construction. Both houses were monitored over a six-month period (from summer to winter) for air exchange rates, electric energy use for space conditioning, indoor and outdoor air pollutant concentrations, indoor temperatures, and weather conditions.



Monitoring Results

Monitoring showed that uncontrolled air exchange rates were about 25% lower in the weatherized house, which also used 10–15% less electric energy for space heating. The most surprising results involved the air pollutant levels, all of which, with the exception of radon gas levels, grew by less than 10% as a result of tightening the house. Radon and the elements it decays to (progeny) were 25–35% higher in the weatherized house than in the control house during the summer (without the heat exchanger or other ventilation fans operating). In the winter, however, total radon levels fell dramatically, and the difference between the two houses became negligible. Radon gas and its progeny are of concern because in sufficiently high concentrations they are thought to cause lung cancer.

mental and the control houses allowed the research team to determine the extent to which the weatherization retrofit saved energy, on the one hand, and changed air quality, on the other.

The houses were unoccupied, although certain activities, such as periodic use of a gas range, were simulated for both. The investigation focused especially on those pollutants that depend on the geology of the site and the materials used to construct the building. "We chose to keep the houses unoccupied in order to sharpen our understanding of physical processes," explains Niren Nagda of Geomet, adding that occupant activities at this stage of the research could have confounded the results. Measurements were taken of air exchange rates, energy use, pollutant levels indoors and outdoors, temperatures indoors and outdoors, and other weather variables. Parallel monitoring of the two houses took place in the summer, fall, and winter to examine seasonal effects.

Weatherizing the experimental house made it 40% tighter than the control house when tested with high-pressure blowers. Under natural conditions, tracer gas experiments showed that the weatherization reduced actual air infiltration by 24%. Average air infiltration rates were 0.33 ac/h for the control house and 0.25 ac/h for the house with the weatherization retrofit.

Greater and more unexpected than the effect of tightening was the impact of seasonal change. Differences between the summer and winter infiltration rates were substantially greater than the difference caused by the weatherization itself. The average hourly air exchange rate for mild summer weather doubled in the fall, and more than doubled again with the advent of winter. The full range covered nearly a 20-fold variation: from 0.05 to 0.96 ac/h for the control house, and from 0.03 to 0.75 ac/h for the house with retrofit weatherization.

As for energy use, the weatherization did indeed provide savings. Cooling benefits were negligible, less than 3%. Heating energy use, however, declined by about 15%. The effect of weatherization on indoor air quality varied considerably, depending on the pollutant in question. For radon, the increase was marked. The retrofit boosted radon gas levels by 30–50% in the summer and fall. Radon progeny concentrations also rose during those seasons, by 20–35%, although winter measurements showed no increase.

The effect of house-tightening on other indoor pollutants was surprisingly small. Carbon monoxide levels from the operation of a standard gas range increased only about 10%. A very slight increase occurred in concentrations of nitrogen dioxide, and formaldehyde concentrations on average did not increase at all. Occasional use of a wood stove was the only indoor source of inhalable particles, and outdoor particle concentrations were low, so weatherization also produced no effect on this pollutant. Clearly, the increase in common pollutant levels, except for radon, was not proportional to the tightening effect achieved by the weatherization retrofit.

Control options

How can a homeowner control air quality problems in a tight house without throwing open the windows and wasting valuable energy? The Geomet research team tested the efficacy of an air-to-air heat exchanger as part of the experimental plan. Information on other possible methods of controlling indoor air quality, such as the use of a range exhaust fan or a central circulation fan, emerged as a by-product of the study. Overall, the results suggest that a simple solution is often the most cost-effective.

The air-to-air heat exchanger is a ventilation device that saves energy by capturing heat from the stale air being expelled and transferring it to the incoming air. Running an air-to-air heat exchanger in the experimental house at a flow setting of 100 m^3/h essentially doubled the air exchange rate. The total energy penalty from loss of indoor heat, plus the device's fan power consumption, varied according to season.

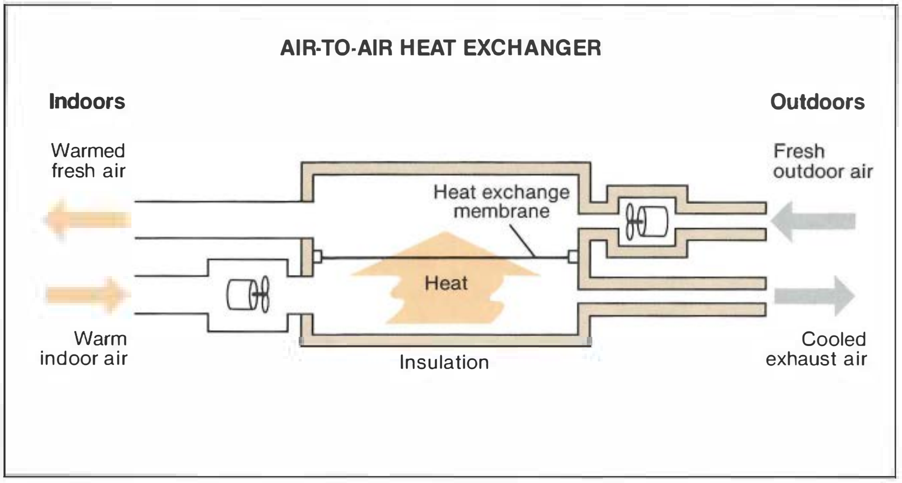
During the heating season, use of the heat exchanger reduced energy savings from 15% to about 6%. Operation of the heat exchanger during the cooling season incurred an energy penalty of 10–15%. Taking into account the heating season's greater length and other seasonal factors, the consequence is that the weatherized house and the control house would consume almost the same amount of energy on an annual basis. In addition, it is worth noting that the heat exchanger ran continuously during the monitoring periods in this study, which may have exaggerated both its energy costs and its air quality benefits for actual home use. Air quality effects of using the heat exchanger varied according to pollutant. The reduction in radon and its progeny was roughly proportional to the change in air flow; that is, doubling the air exchange rate cut radon concentrations in half. Formaldehyde levels were less affected, declining by 30%. Combustion product levels dropped unevenly. One-hour peak concentrations of carbon monoxide fell by 24%, whereas the peak for nitrogen dioxide, which is more chemically reactive with indoor surfaces and hence less dependent on air exchange for removal, was down by only 9%. The very low level of inhalable particles indoors—a level attributable to lack of indoor sources—actually increased during operation of the heat exchanger. The device brought in fresh air from outdoors, where particle concentrations were higher. Indoor concentrations of the other pollutants were able to fall because radon and formaldehyde concentrations are typically low outdoors, and concentrations of most combustion products happened to be low outdoors at the time the experiment was conducted. These results underscore the fact that the outdoors can be a source as well as a sink for indoor pollutants, an important caveat when control strategies that rely on ventilation are employed.

An alternative way to clear the air

around a gas stove is to operate an exhaust fan in the range hood. A range fan lacks the heat recovery ability of a heat exchanger, but it need only be operated when the gas range is on, so the period of any energy loss is quite limited. During these tests, the range hood fan was able to cut eight-hour average concentrations of carbon monoxide in half, just as the heat exchanger did. Being source-specific, it was also more effective in reducing carbon monoxide and nitrogen dioxide peaks by 50% and 40%, respectively, versus reductions of 25% and 10% achieved by the heat exchanger.

A third option tested was the use of a central circulation fan for radon control. A circulation fan mixes the air, redistributes the gas, and enhances the process whereby newly formed radon progeny are removed from the air by plating out on available surfaces. The results with a circulation fan (about a 40% drop in airborne levels of radon progeny) were the same as those achieved by the heat exchanger through removal of the parent gas. The upshot of this work with indoor pollutant controls is that the most efficient solutions tend to be specific to a pollutant, to a house, or even to a particular source within that house, as well as to weather and air quality conditions in the surrounding area.

An air-to-air heat exchanger can freshen the air in any house and reduce all pollutant levels to some extent, assuming that pollutant levels are low outdoors; it is particularly appropriate for tight homes in severe climates with significant indoor pollutant sources. But it is not the best solution in every situation. Geomet's work indicates that other control devices can be equally or more effective, as well as considerably less costly to purchase and install. A final aspect of the present Geomet effort is its contribution to modeling of air infiltration, energy use, and air quality in buildings. Tapping the rich store of measured data generated by this experiment, models were developed that could explain as much as 90% of the variation in hourly air infiltration rates; 90–95% of the daily variation in heating energy use during the winter; 60–90% of the hourly variations in indoor concentrations of carbon monoxide, nitrogen dioxide, and radon progeny; and nearly 90% of the daily variation in formaldehyde levels. This parallel approach of data analysis and model development provided a solid physical basis for interpretation of the study results.



Changing Air, Saving Heat

Air-to-air heat exchangers are sometimes used to ensure that adequate ventilation is maintained in tightly sealed houses. Inside the heat exchanger, warm indoor air leaving the building releases heat to colder incoming air. The Geomet study found that the heat exchanger did improve indoor air quality (reducing levels of radon and its progeny by about 50%) while maintaining the weatherized home's energy conservation advantages. A circulation fan and exhaust hood over the gas range proved similarly effective in reducing pollutant levels, but these devices do not have the energy conservation attributes of the heat exchanger.

Integrating the research

Tightening the experimental house in this study produced variable effects on the pollutants that were measured. Although it yielded a small increase in concentrations of carbon monoxide and a larger increase in radon and radon progeny, it had virtually no effect on nitrogen dioxide or formaldehyde. The effect of weatherization on inhalable particles could not be determined because of a lack of indoor sources.

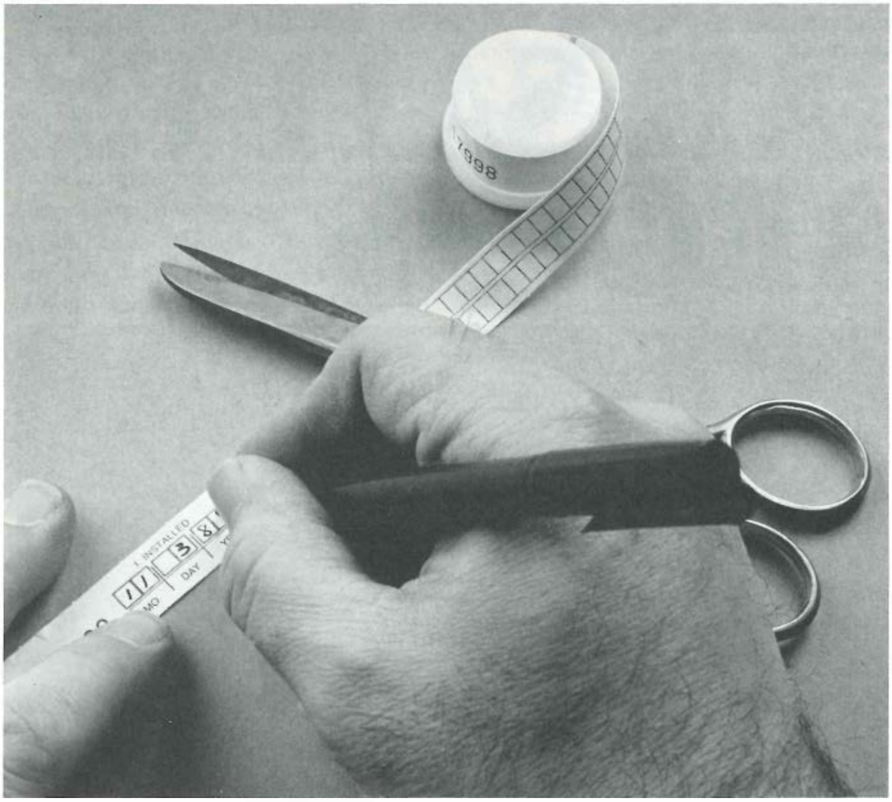
These findings suggest that the air quality consequences of basic home weatherization may be minimal unless significant indoor pollutant sources are present. But the results so far are limited to two homes in a single location, and indoor air quality varies a great deal by region. The weather that drives air infiltration rates is clearly regional in character. Less obvious but also very important are regional variations in radon sources, in the use of wood stoves and kerosene heaters, and in home construction types. Both the specific nature of air quality problems and the appropriate strategies for coping with them will probably have to be explored at a regional or even a local level.

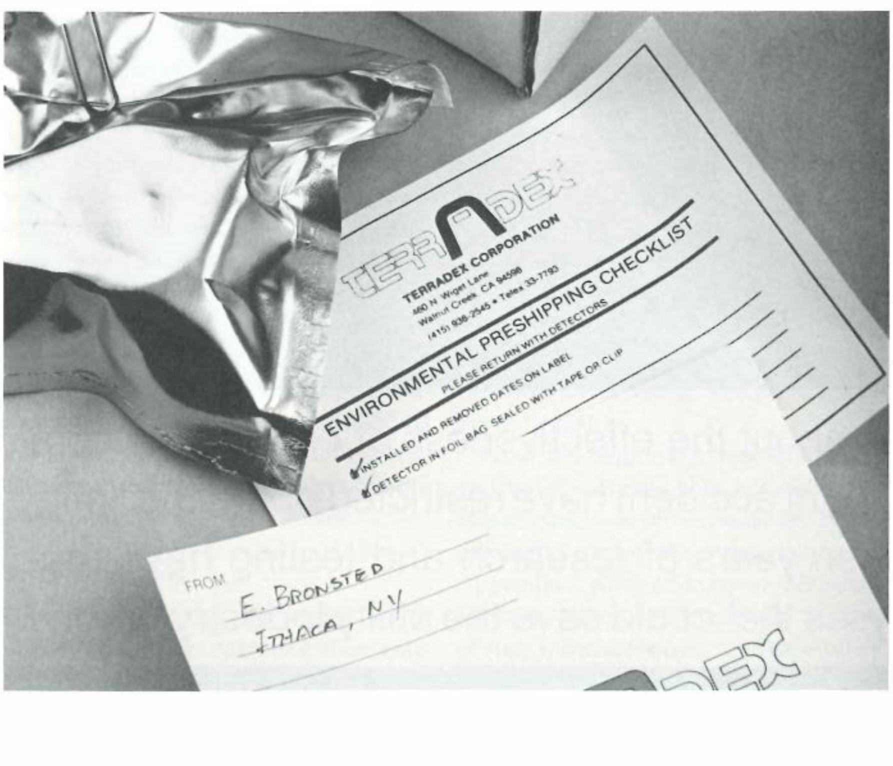
Future EPRI-sponsored work by Geomet will consolidate utility data from homes in diverse parts of the country to see whether some of the patterns found in this study appear on a broader scale. It will also use the two test homes in Maryland for further research on control strategies for radon and radon progeny. And it will take the logical next step in quantifying indoor pollution dynamics by studying the effects of occupancy.

Yet quantifying the physical processes that occur in buildings, occupied or not, is only part of the challenge in dealing with air quality issues. The other part is quantifying the effect of indoor pollutants on human health. To know how

Detecting Indoor Pollutants

Several relatively inexpensive (under $75), easy-to-use devices are available to detect formaldehyde, radon, and nitrogen dioxide. These devices are installed in the space to be monitored for a specified period and then sent to a laboratory for analysis. Comparing the results with existing standards and with levels known to cause health problems can help determine if the building in question has an indoor pollution problem.





tight is really too tight, we have to know more about human responses to the pollutant dose that an indoor environment can deliver.

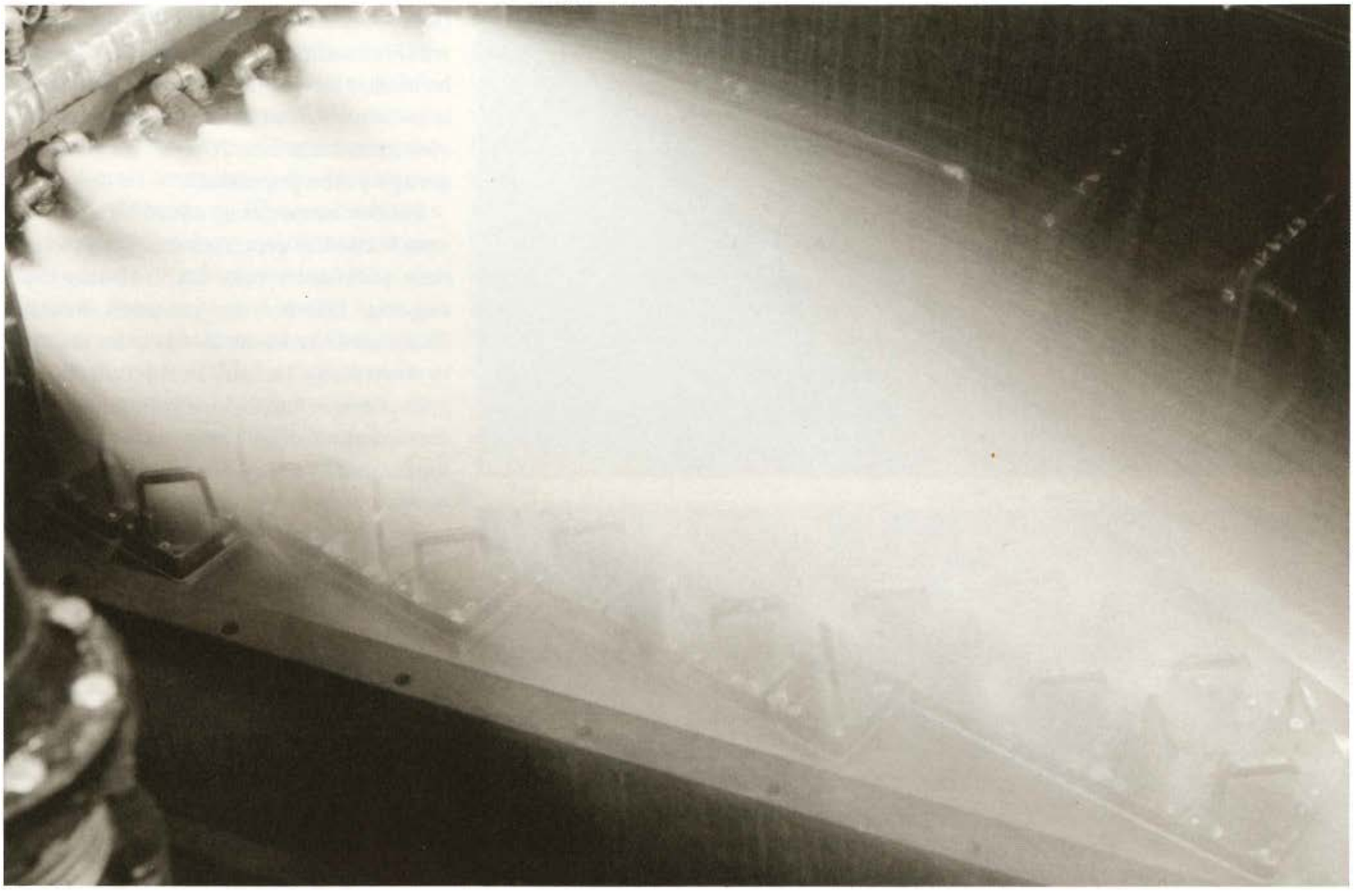
"I believe that we'll understand the physical processes in buildings long before we understand the cumulative health effects," says Gary Purcell, project manager for residential buildings research within the newly created Energy Utilization Department of the Energy Management and Utilization (EMU) Division. Cary Young, project manager working with air quality health effects for the Energy Analysis and Environment (EAE) Division, agrees. "We do know what substances to be concerned about," he adds, "but we don't know in any systematic way what levels of indoor exposure constitute health risks for various groups in the population."

Besides cooperating with EMU on research into the processes that govern indoor pollutant levels, EAE cofunds the ongoing Harvard air pollution health study, also known as the six cities study, to assess the human health effects of both outdoor and indoor pollutants. The current phase of this study is monitoring the air quality of 300 homes in each of six communities to develop pollutant exposure estimates for the people living there. Eventually, these exposure estimates will be correlated with data collected on the respiratory health of the residents to assess the effects of pollutant exposure over time.

Combining research on energy-efficient buildings with health effects studies provides an integrated approach to the questions surrounding indoor air quality. EPRI is funding about $3 million in research over five years. As the work continues, more information will emerge to support decisions that are sound in terms of both energy conservation and air quality goals. ■

This article was written by Mary Wayne, science writer. Technical background information was provided by Gary Purcell, Energy Management and Utilization Division, and Cary Young, Energy Analysis and Environment Division.

REEVALUATING NUCLEAR SAFETY MARGINS



Conservative assumptions about the effectiveness of emergency core cooling during a loss-of-coolant accident have restricted operating limits for many nuclear plants. Ten years of research and testing have produced more-realistic analyses that could save the utility industry billions of dollars.

During the early 1970s serious questions were raised about whether reactor safety systems could cope adequately with a loss-of-coolant accident (LOCA) that might result, for example, from the rapid loss of water from a broken pipe. After such an accident, it was suggested, fresh water from the emergency core cooling system (ECCS) might not be able to penetrate a reactor core quickly enough to prevent fuel rods from overheating, thus sustaining permanent damage. These concerns were aired in a lengthy and often acrimonious series of hearings that resulted in the promulgation of new regulations, which forced utilities to make costly changes in their reactor operations and fuel cycles.

At the time these regulations were introduced, there was widespread agreement that they were probably too conservative and that some of the cost penalties they imposed were unnecessary. The problem was that not enough information was then available to satisfactorily predict reactor behavior during a LOCA. Now, after more than a decade of intensive research—sponsored by EPRI, the Nuclear Regulatory Commission (NRC), and reactor manufacturers—most of the required information has been gathered.

The research both confirmed the fundamental adequacy of existing ECCS designs and revealed those portions of the regulations that were unnecessarily conservative. Because of the new experimental data and analytic methods produced by this cooperative effort, the behavior of reactors is now better understood for a variety of transient conditions, and safety margins can be calculated more accurately. As a result, NRC is considering modifications to LOCA regulations that could potentially save the utility industry billions of dollars.

Costly regulations

The so-called LOCA rule, under which utilities have been operating their reactors since 1973, contains two different types of regulatory considerations. The first, embodied in a section of the Code of Federal Regulations (10 CFR 50.46), establishes acceptance criteria for a reactor's ECCS. Among other provisions, it requires that the emergency cooling system keep the hottest portion of the hottest fuel rod in a core below 2200°F (1200°C) during a LOCA. Relatively little controversy has surrounded this figure because reactor manufacturers have always been confident that core temperatures could be kept well below it.

What has remained controversial is how one goes about calculating core temperatures under the specified conditions of a design-basis LOCA. The approved methods for demonstrating ECCS conformance with the code acceptance criteria were set forth in the separate, highly detailed Appendix K. These analytic methods were both conservative and prescriptive; when specific information about a phenomenon was lacking, worst-case assumptions were prescribed. In other words, a manufacturer trying to calculate fuel rod temperatures was not allowed to make a best-estimate analysis of how emergency cooling water would flow through the core but had to assume conditions that would yield the highest temperatures.

The provisions of Appendix K had an immediate and costly effect on reactor operations. Because of the conservative way fuel rod temperatures were to be calculated in case of coolant loss, some reactors had to run at reduced power and others had to undergo changes in fuel design and reloading schedules. The overall result was lower power generation revenues, higher fuel costs, increased maintenance, and less operational flexibility.

From the beginning, reactor vendors and utilities argued that not only were these restrictions unnecessary but the individually conservative assumptions of Appendix K suffered from serious inconsistencies when used together. Because of such inconsistencies, the Appendix K approach can only be used in establishing highly conservative margins in licensing calculations and not in the actual design of safer reactor systems, which requires a best-estimate approach.

Research needs

In promulgating the LOCA rule, the Atomic Energy Commission (forerunner of NRC) stated its intent "to provide latitude for change when new research information becomes available." This research, now essentially complete, covered a variety of technical issues, ranging from fundamental studies of heat transfer from metal surfaces and the flow of two-phase fluids (liquid and gas together) to complex questions about reactor system behavior, which sometimes required construction of major experimental facilities.

For pressurized water reactors (PWRs), the major question involved what happens when emergency cooling water floods into the bottom of a reactor vessel after the initial blowdown, or loss of coolant. Concerns were expressed that the upward flow of water during this reflood period might be impeded by blockages formed when fuel rods overheated and either bent or developed balloonlike protuberances in their cladding. Such blockages, it was argued, might divert the movement of water enough that it would totally vaporize and not sufficiently cool small regions of the core and perhaps create even more severe fuel rod damage. (Steam removes heat far less efficiently than would water or a two-phase mixture.)

Because the actual effect of blockages was not certain at the time, Appendix K requires that reflood calculations assume only cooling by steam if ECCS flooding flow rates fall below 1 in/s (25.4 mm/s). This assumption produces very high calculated fuel rod temperatures in the region of a blockage during a LOCA. As a result, the operating constraints on power ratings at a number of PWRs in the United States have had to be increased to keep calculated peak temperatures below the 2200°F (1200°C) limit in a design-basis LOCA analysis.

In boiling water reactors (BWRs), emergency cooling water is sprayed over the core through nozzles mounted on a circular pipe. The major question raised about the effectiveness of this type of ECCS was whether formation of steam in the hot core might prevent further penetration of water from overhead. The mechanism postulated as the possible cause of this problem is called countercurrent flow limitation and involves the entrainment of ECCS water by steam moving rapidly upward from within the core. Because of this limitation, it was suggested that cooling water might not reach the bottom of a reactor vessel after a LOCA.

The Appendix K calculations intended to account for the countercurrent flow limitation were based on studies of steam formation in single fuel bundles, which contained fuel rods in an 8×8 arrangement. Such experiments could not take into account the flow of water through a whole section of the core, including bypass channels interspersed between the bundles. As a result of these conservative calculations, changes had to be made in the arrangement and replacement schedule of fuel rods in some BWRs. Such changes did reduce the calculated peak rod temperatures but also greatly increased fuel and maintenance costs.

To investigate these phenomena more carefully and determine whether or not the hypothesized ECCS problems would really develop, the recently concluded program of jointly sponsored research was established. Westinghouse Electric Corp. was to conduct the major experiments involving PWRs and General Electric Co. would conduct those involving BWRs. The purpose of this effort was to produce definitive data on what happens in a reactor when coolant is lost and to incorporate these data into computer codes that could adequately model reactor behavior under LOCA conditions. Early, jointly sponsored tests were also conducted by Combustion Engineering, Inc., and Westinghouse to study the dynamic mixing of cold ECCS water with flowing steam. On the basis of information gathered from such research, Westinghouse and General Electric have been developing their own proprietary codes for use in reactor licensing, using best-estimate methods rather than the assumptions prescribed in Appendix K.

PWR reflood blockage tests

Most of the Westinghouse work was conducted as part of a six-year, $18 million program called FLECHT–SEASET (full-length emergency core heat transfer–separate-effects and system-effects test), using facilities at Forest Hills and Monroeville, Pennsylvania.

Tests were conducted with bundles of electrically heated rods that simulated a portion of a PWR core. The 0.374-in (9.5-mm) heated rods were identical in size to the fuel rods in a Westinghouse fuel assembly, with a 12-ft (3.7-m) heated length, and were tested in a pressurized vessel equipped with scaled piping and extensive instrumentation.

Two sets of experiments were run to study the effects of blockage during reflood. Tests using a 21-rod bundle provided the opportunity to evaluate many different blockage shapes and configurations. Clad swelling was simulated by ballooned sleeves fitted over various heated rods. These tests primarily provided a model for more-detailed work with a larger bundle, but they also established that water droplets moving along with the steam contribute significantly to the cooling of rods in a blocked area, as well as downstream. In other words, the Appendix K assumption that such cooling resulted only from steam was overconservative because of the existence of a two-phase mixture of steam and water droplets.

A detailed study of this phenomenon was provided by tests on a 163-rod bundle. These tests were conducted by using the blockage configurations that showed the poorest heat transfer during the 21-rod bundle experiments. Not only did the larger bundle work confirm the earlier finding that water droplets, as well as steam, contribute to cooling, it also showed that cooling was actually enhanced. Because of turbulence in the immediate vicinity of the blockage area, rods are cooled more efficiently by the steam-water mixture than by the passage of pure steam only. As a result of this effect, the actual rod temperatures were found to be some 600–700°F (315–370°C) lower than those calculated by using Appendix K assumptions.

In addition to the blockage tests, FLECHT–SEASET included experiments on unblocked bundles. Some of these tests were related to Appendix K calculations and aimed at providing information about reflood effects on new fuel designs and the release of heat from a nuclear plant's steam generator during reactor reflood. Other unblocked bundle tests were related to questions raised in the wake of the Three Mile Island accident, including changes in rod temperature following a small-break LOCA or an operational transient.

The data collected from FLECHT–SEASET have now been used to develop improved analytic models of PWR behavior during reflood. In particular, the information on bundle blockage has been incorporated into a computer code called COBRA–TF. Based on an existing analysis method, this code was developed jointly by Westinghouse and Battelle, Pacific Northwest Laboratory to provide a technical basis for modifying the prescribed evaluation methods of Appendix K related to blockage. The information gathered in unblocked bundle tests is being used in modifying other standard reactor analysis codes. As a result, the best-estimate calculation of peak rod temperature during reflood in a PWR is now roughly 1200°F (650°C) less than that derived by using Appendix K assumptions.

BWR core penetration tests

The General Electric work on ECCS performance in BWRs cost approximately

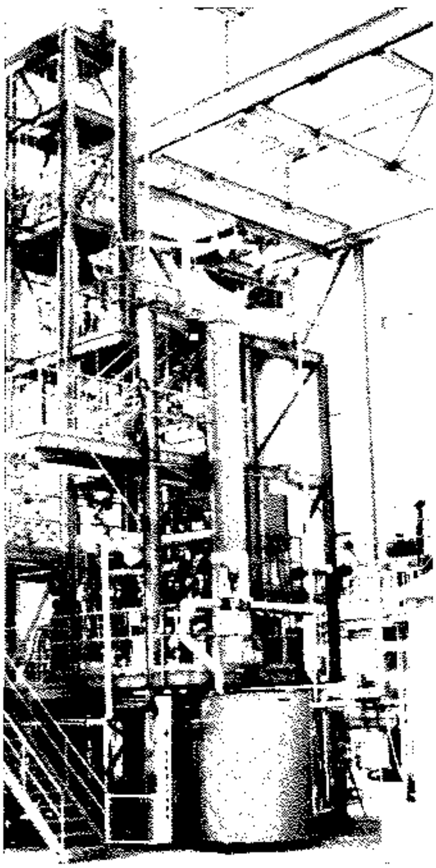
$16 million and has taken more than eight years to complete. This research involved single-bundle tests at facilities in San Jose, California, and tests on a full-scale mock-up facility in Lynn, Massachusetts. The single-bundle tests used electrically heated rods and simulated the full range of temperature and pressure conditions during a LOCA. These experiments set the stage for the full-scale tests, which could simulate regional flow variations within a reactor but not specific rod temperatures. (The use of electrically heated rods in so large a facility would have been prohibitively expensive.)

The first single-bundle tests used the two-loop test apparatus, which provided simulation of fuel behavior during the blowdown phase of a LOCA. Later, a full integral simulation test (FIST) apparatus, which had the added capability of a full-height representation of the reactor, was used to simulate LOCA conditions from initial break to completed reflood. The FIST facility was also used to explore bundle behavior during a wide range of operational transients. These experiments showed that ECCS water injection could keep rod temperatures within safe limits—even in a single-bundle apparatus that does not simulate regional flow effects—but they left open the question about the ultimate importance of countercurrent flow limitation.

To address this issue, research was conducted at General Electric's Steam Sector Test Facility (SSTF), which consists of a full-scale, 30° sector of a BWR and uses steam injection to simulate core heat. This facility was used to study phenomena, such as countercurrent flow limitation, that are sensitive to scale size or require multiple fuel bundles to simulate. Tests at SSTF showed unambiguously that emergency cooling water is always able to flow freely through the core and rapidly refill the reactor vessel. At the periphery of the core, countercurrent flow rapidly broke down after ECCS was turned on and the steam condensed, allowing water to flow downward unimpeded. Flow in bundles at the center of the core actually speeded up the flooding process by venting steam formed in the lower part of the vessel.

BWR Test Facilities

Single bundles of BWR fuel rods were heated electrically at a test facility in San Jose, California (top), to simulate the full range of temperature and pressure conditions during a LOCA. Results from this research and from tests at a full-scale mockup facility in Lynn, Massachusetts (bottom), showed that ECCS water injection systems are extremely effective in keeping rod temperatures within safe limits during an accident.



These data were incorporated into another government-originated computer code, now called TRAC–BD, which can provide a greatly improved model of BWR behavior during a LOCA. The code modifications were undertaken jointly by General Electric and the Idaho National Engineering Laboratory in order to offer an alternative to Appendix K analysis. On the basis of the new data and code, the best-estimate calculation of peak rod temperature during ECCS operation in a BWR is more than 1400°F (778°C) below that derived by using the assumptions of Appendix K.

Related experiments

In addition to the major research projects devoted to the two specific questions of ECCS performance, a considerable amount of related experimental work addressed other LOCA issues. The results of this work—also jointly sponsored by EPRI and NRC, but including a number of third parties—are also being used to reassess the evaluation methods of Appendix K.

Experimental and analytic studies aimed at predicting the maximum flow rate from a break during a LOCA were conducted by an international consortium at the Marviken Full-Scale Facility in Sweden. This unique facility enabled researchers to discharge various mixtures of water and steam from a full-sized reactor vessel through a large-diameter pipe. The data gathered were compared with figures produced by currently applied computer models and revealed that these generally tend to overpredict the flow rate. An improved critical flow model was then developed in a form that can be used as a module in larger reactor transient codes, such as EPRI's RETRAN.

In a coordinated program, the response of a reactor pump under two-phase flow conditions was determined to evaluate, in part, how much flow may go through the reactor core during various phases of a LOCA.

Once a reactor is shut down in response to a LOCA, its fuel rods continue to release heat because of radioactive decay of fission isotopes. At the time the LOCA rule was adopted, the American Nuclear Society proposed a standard defining this so-called decay heat; but because of uncertainties surrounding heat generation for short cooling times, Appendix K prescribes a value 20% higher than the standard. To help remove the uncertainties, a series of four experiments were conducted with NRC and EPRI sponsorship to determine the decay heat generated individually by key isotopes, and these data were incorporated into a highly detailed analytic model. The model has now been applied successfully to predict the measured decay heat of typical PWR and BWR plants. These studies demonstrated that the Appendix K assumptions related to decay heat were indeed overly conservative and that the new methodology provides a more accurate calculation of the phenomenon.

Another significant question related to reactor safety during a LOCA concerns the oxidation and deformation at high temperatures of the Zircaloy cladding that covers fuel rods. This question presents a particularly challenging analytic problem because oxidation kinetics is quite complex and metal deformation depends not only on the temperature at a given time but also on the temperature history of a specimen. Initial, nonreactor experiments showed that the oxidation rates calculated by using Appendix K were at least 80% too high. Further work to determine the effect of this and other findings on the behavior of fuel rods in a working reactor is still in progress at the internationally sponsored Halden Reactor Project in Norway.

Utility benefits

"This joint research program could not have occurred without strong utility support," says Romney Duffey, the senior program manager who spearheaded EPRI's participation in the effort from 1977 to 1984. "The LOCA rule was the number-one issue nuclear utilities were facing before Three Mile Island, and the utilities were very, very supportive of our efforts. They saw the benefit of combining our funds with those of the government and reactor manufacturers, and now they should begin reaping substantial benefits. At the very least we have demonstrated that present plants have quite adequate safety margins. And with the new data and analytic tools available, utilities should also gain considerably more flexibility in operating their reactors and planning their fuel cycles."

The program was created through a series of three-way agreements in which EPRI's role was crucial, according to Duffey. EPRI's participation as a third party not involved in licensing activities enabled the vendors and the government to contribute funds to an independent, jointly managed enterprise. Each party in the agreements fully delegated management responsibility to its representative and, in cases of conflict, the contracts specified dispute procedures that shifted the responsibility upward through the managements of the participating organizations.

"I believe the arrangement was highly successful," comments Duffey. "We had some differences of opinion, but I think that's very healthy. The programs have been better because of the spirited interactions among the parties."

On those projects covered by the contracts, NRC assumed 42% of the cost; EPRI, 33%; and the vendors, 25%. EPRI's total costs on LOCA-related research have been nearly $35 million, including the supporting studies conducted at universities and private laboratories. The total NRC expenditures related to the LOCA rule, which have included other research that did not involve EPRI, are now reported to be more than $700 million. These included very significant large-scale tests at the Semiscale facility and the LOFT reactor at the Idaho National Engineering Laboratory.

A few utilities may choose to apply the results of LOCA research to their own licensing submittals, Duffey admits, but most are likely to take advantage of this work through analyses performed by the nuclear vendors. Because COBRA–TF and TRAC–BD are generally considered benchmark codes, which can provide the most accurate analysis of LOCA events but are too detailed for routine use, individual reactor manufacturers and nuclear fuel suppliers are developing their own simplified, proprietary versions.

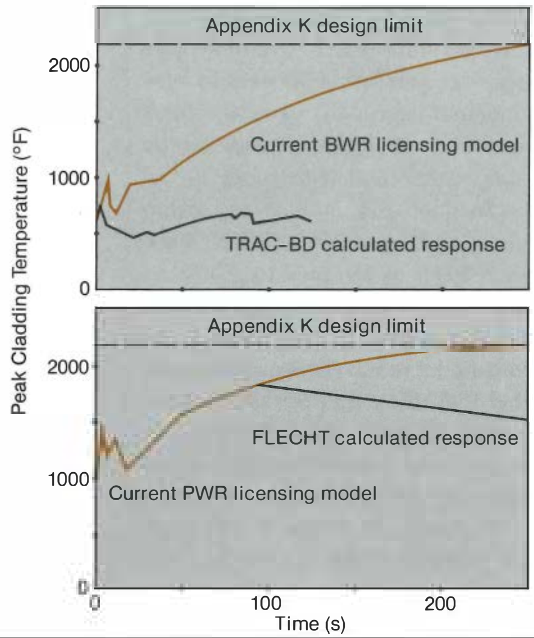
The first of these proprietary codes, SAFER–GESTR, developed by General Electric, have recently been approved for use in licensing submittals as a substitute for earlier Appendix K models. In a recent EPRI study using this SAFER–GESTR code package, General Electric has shown that the required starting time for a diesel generator at a BWR-6 plant can be increased to nearly 120 s, compared with the currently specified 10 s. This finding should help utilities reduce diesel degradation (i.e., reduced diesel generator stress and wear) from excessive testing and also favorably affect the station blackout issue, where maintaining high reliability is important.

This approach is just one of three the NRC is making available to licensees as it attempts to revise the LOCA rule, according to Program Manager Bindi Chexal, who is coordinating EPRI's efforts to provide technical information for the revision. The other two options are to accept the current Appendix K analysis or to conduct a full best-estimate analysis with a 95% certainty. The disadvantage of the latter approach, compared with substituting specific best-estimate figures in Appendix K calculations (as General Electric has done), is that it requires far more computation time.

"NRC expects that the substitution approach will only be temporary, and its staff is preparing a Regulatory Guide on how to make the required best-estimate-plus-certainty calculations," says Chexal. "Using a more realistic analysis

Defining Design Limits

The combination of new LOCA data and an improved TRAC-BD computer code provides a more accurate (and much lower) calculation for peak rod temperatures in BWRs than do traditional methods. These and similar calculations for PWR reflood clearly demonstrate that Appendix K assumptions for fuel rod decay heat are overly conservative and may unreasonably restrict LWR operating limits.



of LOCAs could ultimately save each nuclear plant \$50–\$100 million over its lifetime by allowing greater operational flexibility and better fuel cycle planning. In addition, plant life may be extended because more margin will be provided for fuel loadings that minimize neutron flux at the reactor vessel wall."

Future directions

Although experiments assessing the performance of reactor safety systems during a specified LOCA have now been successfully completed, new research is required to address related questions raised by experiences at Three Mile Island. "What TMI showed us, among other things, is that even if you have a plant that withstands a design-basis LOCA, there are other events that can create reactor conditions in which the core is damaged and radioactivity released," Duffey explains. "As a result, there's a whole new emphasis in reactor safety research. The large-break LOCA is no longer seen as the dominant consideration. Instead, we have begun to concentrate on so-called risk-dominant accidents, involving such occurrences as small-break LOCAs and operational transients." The small-break LOCA is not limiting in Appendix K terms (i.e., with regard to core heatup), but it does challenge procedures and longer-term recovery strategies.

From an experimental and analytic point of view, this shift of emphasis means a major extension of the time scale over which events must be tracked and modeled. The ECCS response to a large-break LOCA is automatic, and the total time to reflood and temperature stabilization is about 2 min. The loss of coolant caused by a small break or by equipment malfunction and operator error (as at TMI) is much slower. A complex series of events may unfold for hours after automatic reactor shutdown (the loss of primary water at TMI was not halted until 2 h, 18 min after shutdown). Although such a slow evolution of events gives operators more time to intervene, the calculations required to model what is going on in the reactor are also proportionately greater. This new research need is reflected in EPRI programs on small-break LOCAs, plant recovery, operator information systems, risk analysis, and radioactivity release (source term programs).

"The culmination of these diverse research and demonstration programs has had a profound impact," says Walter Loewenstein, director of the Nuclear Power Division's Safety Technology Department, under which the work was conducted. "Quantifying safety and prudent operating practices and margins provides a basis for visible, near-term economic benefits. And simplification of installations in response to the findings provides a technical basis for both capital and operating benefits on a longer time scale."

In addition, Loewenstein reports that these projects have had significant impact on how EPRI conducts large and expensive research efforts in cooperation with other national or international participants. "An obvious benefit has been that we could compare these findings with those in other countries, which has led to further verification of the data. With the successful completion of this effort, nuclear safety research can next move from describing accidents and their consequences to using this information to prevent and accommodate accidents with growing confidence. Such work should help remove many of the real and imagined safety concerns that have unduly hampered reactor design and operating practices in the past." ■

Further reading

FLECHT SEASET Program. Final report for RP959-1, prepared by Westinghouse Electric Corp., December 1985. NP-4112.

EPRI R&D Contributions to the Technical Basis for Revision of ECCS Rules. Special Report. Palo Alto, Calif.: Electric Power Research Institute, July 1985. EPRI NP-4146-SR.

BWR FIST: Phase 1, Test Results. Interim report for RP495-1, prepared by General Electric Co., March 1985. EPRI NP-3602.

BWR Refill-Reflood Program. Final report for RP1377-1, prepared by General Electric Co., April 1984. EPRI NP-3093.

This article was written by John Douglas, science writer. Technical background information was supplied primarily by Romney Duffey; additional information was provided by Bindi Chexal, Pal Kalra, Mati Merilo, Avtar Singh, K. H. Sun, and Jean Pierre Sursock, Nuclear Power Division.

Benefits of Heat Rate Improvement Workshop

An EPRI-sponsored heat rate improvement workshop held in September 1983 was conducted to benefit utility personnel who operate and maintain power plant equipment. Months later, a San Diego Gas & Electric Co. (SDG&E) workshop attendee found the workshop particularly valuable. One SDG&E generating unit was performing below normal, and during a scheduled overhaul the utility replaced cracked blades in both the high-pressure (HP) and intermediate-pressure (IP) sections of the turbine. Postoverhaul tests indicated the loss of turbine efficiency had been corrected, but a month later, during a routine test with valves wide open, a 10-MW reduction in power and a 7% loss in HP turbine efficiency were noted. The utility had to decide whether to perform immediate maintenance or to continue operating the turbine and risk a possible forced outage. Using one of the tutorial papers from the workshop and focusing on the diagnosis of reduced HP and IP turbine efficiency, SDG&E decided that its problem lay in the first stages of the HP section of the turbine. The utility learned that continued use of the turbine without immediate repairs could have resulted in a catastrophic equipment failure. When the utility began repairs, it discovered a shroud was missing in the second stage, and pieces had lodged against the following diaphragms, causing restricted steam flow and loss of generated power. SDG&E repaired the unit and restored it to full service. SDG&E estimated that using this workshop material saved it $752,000 in 1984 on the restored load and turbine efficiency alone. This amount does not include the large potential saving by avoiding a possible forced outage. ■ *EPRI Contact: Frank Wong (415) 855-8969*

Electronic Adjustable-Speed Drive for Boiler Feed Pumps

Until 1985 Ft. Churchill Unit 2 at the Sierra Pacific Power Co. (SPP) usually ran at a 16-MW minimum load, acting as a spinning reserve in case of lost generation or transmission on another unit or for reasons of fuel economy. This 16-MW operation was expensive, inefficient, and hard on system pumps and valves. Therefore, SPP worked with EPRI to retrofit a boiler feed pump control system with an adjustable-speed drive (ASD), and installed it on the Ft. Churchill 2A boiler feed pump in 1985, providing variable-speed control by altering the frequency of the power supplied to the induction motor. As a result, Ft. Churchill's minimum load operating capability was reduced to 11 MW, eliminating valve losses and wear on the pump because the pump now supplies just enough pressure to maintain flow to the drum. SPP estimates a total saving of $3,775,000 in operation, maintenance, and fuel costs over a six-year period, in addition to extending the useful lives of pumps and control valves. ■ *EPRI Contact: Ralph Ferraro (415) 855-2557*

Flue Gas Desulfurization Liquid Equilibrium Model

Utilities can now analyze scrubber liquors and determine flue gas desulfurization (FGD) performance indicator values with a new, easy-to-use computer program: FGDLIQEQ. Originally developed for the U.S. Environmental Protection Agency, an improved version of the program has been adapted from a mainframe format for use on the IBM PC. The calculated performance indicators represent some of the primary factors that control the FGD process, including relative saturation of solid phases and dissolved alkalinity. When these factors are not controlled, FGD process efficiency can drop and/or scaling can occur. The program can also be used to determine ion balance, an indicator of the quality of the analytic data. Volume 3 of the *FGD Chemistry and Analytical Methods Handbook* (CS-3612) contains the program instruction manual. (Volume 1 describes the FGD chemistry, and Volume 2 covers the analytic methods.) FGDLIQEQ is being used by the Arizona Public Service Co. (APS) at its Four Corners plant lime FGD system and at the Cholla plant limestone FGD system to compute certain performance indicator values. These values enable utility personnel to better monitor the FGD process and adjust operating conditions to prevent scaling and improve system performance. By using FGDLIQEQ, APS anticipates a levelized annual saving of approximately $168,000 for the next 10 years. ■ *EPRI Contact: Dorothy Stewart (415) 855-2609*

Groundline Pole Repair Process Saves Time and Money

Extending the life of wood transmission and distribution poles has been a continuing goal for the electric utility industry. Wood poles can fall victim to fungus, termites, rot, automobiles, and old age. Pole replacement is expensive, and stubbing (bracing a pole with another pole) can be unsightly. Groundline wood pole repair is a popular new approach for repairing poles that have been weakened or broken at ground level. If required, the pole is first treated to retard any further biologic deterioration. Next, special steel casing is driven into the ground around the pole, forming a metal sleeve. Finally, a grout or resin-based product is used to fill the small space between the pole and the sleeve; when the grout hardens, the repair is complete. In 1985 Arizona Public Service Co. (APS) tested this repair process on poles in Scottsdale, Arizona, with an EPRI licensee, Loadmaster Systems Inc., performing the repairs. APS estimates that it will save $312,000 on a two-year project repairing 260 poles with the pole repair method. These repairs are faster (some take only one hour) and are usually less expensive than pole replacement. No service interruptions are required, and the completed repair is more attractive than a stubbed pole. ■ *EPRI Contact: Vito Longo (415) 855-2287*

Analysis of Power Cycles for Geothermal Wellhead Conversion Systems

To help utilities match optimal power cycles to specific geothermal sites, EPRI completed a study of different working fluids and power cycles in the range of representative resource and condensing temperatures. Five state-of-the-art flashed and binary power cycles were considered. In all, 240 combinations were analyzed to identify the most efficient cycles and working fluids for each resource temperature range. Results of the study, reported in *Analysis of Power Cycles for Geothermal Wellhead Conversion Systems* (AP-4070), reveal the effect of geothermal fluid temperature on power generation. For comparison, at 400°F (204°C) the binary cycle produced 24 Wh/kg of fluid, while at 600°F (316°C) it could produce nearly three times as much electricity. Conversely, at 200°F (93°C) less than one-tenth as much power can be produced. The results clearly show that optimized binary cycles outperformed one- and two-stage flash cycles at all temperatures, and double-flash cycles had an advantage of 30% over single-flash systems. Using the information contained in this study to estimate net power, thermal efficiency, and key state points of specific cycles for specific sites can save utilities time and money in initial engineering studies. ■ *EPRI Contact: Evan Hughes (415) 855-2179*

Ohio Edison Restores Unit Efficiency With Sonic Horns

Responding to air quality regulations, Ohio Edison Co. installed fabric filter baghouses on each of four 180-MW units at its W. H. Sammis plant by 1982—part of the largest environmental retrofit project of its kind in the United States. The utility soon found that fly ash accumulated on the inner surface of the bags, forming a heavy dustcake. This resulted in high pressure drops, causing the induced-draft fans to consume greater amounts of power and reducing the net output of the generating unit. To alleviate the problem, Ohio Edison turned to research EPRI had conducted on sonic horn cleaning of fabric bags at its fabric filter research facility at Public Service Co. of Colorado's Arapahoe power station. Ohio Edison used EPRI's published results to prepare purchase specifications, to evaluate bids, and to adjust sonic horn sound levels and operating frequency for the horns installed on its Sammis Plant Unit 3. The horns installed on that unit saved an estimated $83,700 annually (levelized), and the utility has now installed sonic horns on the remaining three Sammis units. ■ *EPRI Contact: Walter Piulle (415) 855-2470*

Corrosion-Resistant LP Turbine Blade Coatings

Blades, disks, and rotors in low-pressure steam turbines can fail prematurely because of stress corrosion cracking and corrosion fatigue. Because a significant number of turbine blades fail each year in particular plants within its system, Southern California Edison Co. (SCE), together with Westinghouse Electric Corp., asked EPRI for help in evaluating corrosion-resistant coatings for turbine components. From a large field of possible coatings that were commercially available, EPRI selected 24 for laboratory testing. From this group, 4 coatings were chosen for more-detailed laboratory tests, and 3 of these were given full-scale field tests: ion-vapor-deposited aluminum, nickel-cadmium electroplate, and sulfamate-nickel electroplate. Nickel-cadmium electroplate and ion-vapor-deposited aluminum were demonstrated to be effective coatings in the initial EPRI study. Since SCE began using the recommended coatings on its turbine blades in 1982, there have been no blade failures on the more than 30 rows of coated low-pressure and auxiliary steam turbine blades in the program. SCE estimates that it will save $41.3 million over five years by using these corrosion-resistant coatings on turbine components. ■ *EPRI Contacts: Barry Syrett (415) 855-2956; Thomas McCloskey (415) 855-2655*

R&D Status Report
ADVANCED POWER SYSTEMS DIVISION

Dwain Spencer, Vice President

COOL WATER PROJECT UPDATE

*The performance of the nation's first commercial-scale integrated gasification–combined-cycle (IGCC) power plant, which was commissioned in June 1984 (*EPRI Journal*, December 1984, pp. 16–25), continues to exceed even the most optimistic initial projections. Most of the essential design process parameters pertaining to efficiency, emissions, and availability have already been substantiated on the design coal (Utah bituminous). The main challenge of the next few years will be to prove the availability, reliability, and maintainability of the equipment in utility service and to demonstrate the flexibility of the IGCC concept by processing various coal feedstocks, including high-sulfur bituminous coals from Appalachia and the Midwest, in an efficient and environmentally benign manner.*

The nominal 100-MW plant, which uses a Texaco gasifier to convert coal to a clean fuel gas for a General Electric Co. combined-cycle unit, was built adjacent to Southern California Edison Co.'s 600-MW Cool Water generating station near Daggett, California (Figure 1). Participants include SCE, Texaco Inc., EPRI, General Electric, Bechtel Group, Inc., and the Japan Cool Water Program Partnership. Empire State Electric Energy Research Corp. and Standard Oil of Ohio are contributors.

During the five-year operations phase, price support for the gas produced is provided by the U.S. Synthetic Fuels Corp. based on market conditions; the maximum total of support to be provided is $120 million.

Plant construction was finished in April 1984, only 28 months from the start of site clearance. The first production occurred in May 1984, and a rigorous 10-day acceptance test was completed the following month, marking the initiation of the operations phase.

From initial production through December 31, 1985, the plant generated 700 million kWh of electricity, consuming 300,000 t of coal during 7357 h of gasifier operation. To date most of the essential design projections have been confirmed, as discussed in the following paragraphs.

Cost and construction

A study conducted by Fluor Engineers, Inc., estimated the cost and performance of mature Texaco-based IGCC power plants with output capacities of 100, 250, 500, and 1000 MW (EPRI AP-3084). The actual capital cost of the Cool Water plant, after adjustments for the first-of-a-kind engineering costs, the cost of an oxygen plant, extensive testing provisions, equipment redundancy, and other necessary corrections, matched the corresponding Fluor estimate very closely.

The short construction time (28 mo) confirms another important economic attribute of IGCC systems because full-size commercial plants will probably be built of shop-fabricated components of Cool Water's size. The short commissioning time, doubtless attributable mainly to the planning and dedication of the Cool Water staff, is also a reflection of the maturity of this technology.

Another recent study conducted by Fluor showed that the process used at Cool Water (when integrated with the new-model combustion turbines designed for higher firing temperatures and planned for introduction in the late 1980s) should produce power at a cost about 10% less than that of a direct-coal-fired plant with scrubbers (EPRI AP-3486).

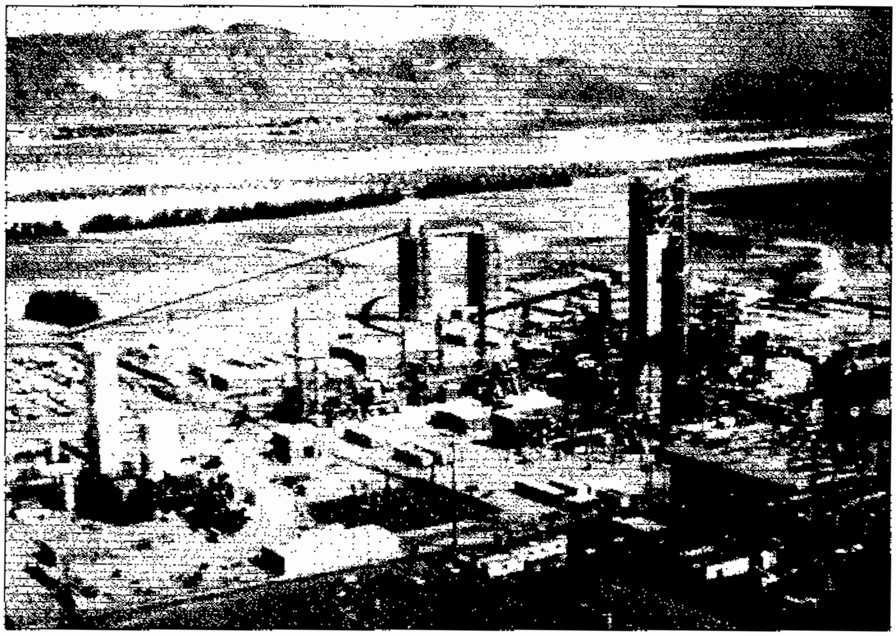


Figure 1 The Cool Water IGCC power plant, the first commercial-scale plant of this type in the United States. Results from the first year and a half of operation are very encouraging. Ongoing tests are addressing reliability, availability, feedstock flexibility, and environmental performance.

Performance

The several aspects of gasifier scale-up have already been successfully demonstrated. Design coal throughput (1000 t/d dry coal) has been routinely achieved. The carbon conversion, typically 98–99% at the design oxygen/carbon ratio of 0.99:1, exceeds the design estimate of 95% by a significant margin. At these high conversion efficiencies it does not appear worthwhile to recycle the slag, although provisions were made in the design to allow for recycling.

The slurry concentration used to date has typically been about the design value of 60% (by weight dry solids). Techniques for increasing the slurry concentration are being explored and should increase gasifier and plant efficiency when they are incorporated into plant operations. Currently, the gasifier cold-gas efficiency is a little higher than design, reflecting the higher-than-design carbon conversion upstream. All these performance indicators demonstrate the successful scale-up of the Texaco burner.

Long-term materials reliability is an ongoing concern. The bricks that form the refractory lining of the gasifier must withstand the heat of the gasification reaction and the abrasion of the passing coal slag and ash particles. Refractory life is of significant economic importance. On the basis of experience to date, a refractory operating life of 10,000 h is currently estimated.

Another uncertainty has been the possibility of fouling of the heat transfer surface in the syngas cooler. Slag solidifies during its 120-ft (37-m) fall through the radiant cooler and at some point passes through the sticky phase when it could adhere to the walls. Preliminary data indicate less fouling than had been contemplated in the radiant section.

On a few test runs there was some fouling at the crossover duct between the radiant and convective coolers. Soot blowers installed in this location during the November 1985 outage appear to have counteracted the problem.

Materials testing is an important part of the test program throughout the plant, but it is especially so for key portions of the syngas coolers because of their size and economic importance. The performance of test tube materials will be closely examined during the upcoming tests of high-sulfur coal. Performance to date on the low-sulfur coal has been quite satisfactory.

Full-load output has been achieved. The plant has generally been operating at a net heat rate of about 11,500 Btu/kWh, compared with an initial design rate of 11,300 Btu/kWh. Scheduled maintenance in November 1985 corrected some deficiencies so that the routine operating heat rate is now near or below the design specification. Future changes may bring the heat rate down to about 10,600 Btu/kWh.

Table 1
ATMOSPHERIC EMISSIONS
(lb/million Btu coal)

	Test Results	Federal NSPS*
SO_2		
Utah coal (0.5% sulfur)	0.036	0.3
Illinois No. 6 coal (3.5% sulfur)	0.13†	0.6
NO_x	0.06	0.6
Particulates	0.001	0.03

*New Source Performance Standards for coal-fired power plants.

†Preliminary data.

The plant capacity factor (proportion of capacity actually generated) has risen substantially over the first 15 months of operation—from 31% and 41% for the last two quarters of 1984, respectively, to 56%, 32%, and 47% for the four quarters of 1985. The second, fourth, and sixth quarters of operation included planned outages; the fourth quarter included a shutdown to complete the tie-in of the spare gasifier (direct-quench design) and a one-month commissioning effort, which was successfully completed in May 1985. The quench gasifier is less efficient than the main unit because the steam production from the syngas coolers is lost, and this results in a lower plant capacity factor even at full output.

In the third quarter of 1985 the plant was on-stream 76% of the time, and the capacity factor for September 1985 was over 85%. The program's target capacity factor is 50% for 1985, 65% for 1986, and 70% in subsequent years. Cool Water's success in exceeding the planned numbers reflects the maturity of the technology. A big challenge over the next four years will be to achieve or exceed the target 70% annual capacity factor.

Emissions and waste

A major incentive for adopting IGCC technology lies in its superior environmental aspects. The overall emissions are lower than those of a combined-cycle unit fueled with natural gas, and they meet current federal and California standards. As a matter of fact, visitors to Cool Water cannot tell from the stack's appearance whether or not the plant is in operation.

Recent emissions data from sampling the combined cycle's heat recovery steam generator stack show that in all cases the permit requirements have been exceeded (Table 1). The plant permit requirements are considerably more stringent than the corresponding EPA New Source Performance Standards for coal-fired plants (0.60 lb/10^6 Btu for NO_x, 90% removal of SO_2, and particulates of 0.03 lb/10^6 Btu). The NSPS limit for NO_x has also been established for stationary gas turbines at 75 ppm (by volume); Cool Water gas turbine NO_x emissions, measured at 23 ppm, are far below this. Recent preliminary data from Illinois No. 6 coal indicate SO_2 emissions are also far below the NSPS limit.

The California Department of Health Services recently confirmed that the slag discharged from the gasifier, representing the mineral matter in the Utah feed coal, is nonhazardous. A commercial use for this material is being sought. The only other solid product from the plant, the sulfur recovered from the raw syngas product, is already being sold commercially.

Testing

Initial dynamic testing of the Cool Water plant was conducted in September 1985 to assess its load-following capability. Even at this early stage of testing, the results indicate that the plant can meet most utilities' daily load-following requirements. Further improvements are planned.

Load change demands were applied to the overall plant megawatt controller set point. This controller, in turn, asked for an increase in fuel flow to the gasifier. A rate limit of 8%/min was applied at this point. The oxygen plant automatically responded to the change in demand, and the power plant responded to the increased availability of syngas and steam. This arrangement is referred to as the gasifier lead mode. No manual operator intervention was required.

The largest and fastest load change requested was a 20% increase in plant power output at 8%/min. The plant responded at a maximum rate of 3.5%/min and at an average rate of 2.2%/min from the time the demand increase was initiated until the plant output reached the desired set point. Utility daily load-following requirements are usually cited as 10–50% load changes at 1–3%/min. The test results were comfortably within this range, so the plant can meet normal daily load-following requirements.

Further testing is planned in the coordinated control mode where rate change demands are simultaneously applied to the gasifier and the power plant. On the basis of the test results from the gasifier lead mode, EPRI expects the coordinated control mode, along with improved controller tuning, to provide an even faster overall plant response.

Facilities were provided to route the syngas product to an existing SCE 65-MW boiler located at the Cool Water site. In a successful full-rate test of this mode, 1286 MWh of electricity were produced and NO_x emissions were reduced below the unit limits. These and other planned tests will supply performance data on syngas as a boiler fuel for either retrofit or new installations.

Future plans

To date, Utah coal has been processed in the plant. The first alternative coal test, using Illinois No. 6 high-sulfur coal, started December 25, 1985, to be followed by a test with Pittsburgh No. 8 coal in the first quarter of 1986. A broad spectrum of coals are expected to be tested during the remainder of the operations phase.

Extensive data are being collected on environmental performance, materials life, equipment reliability, and system availability. The research will evaluate the dynamic response to load following under alternative control strategies and validate steady-state and dynamic system models. It will also determine operating costs relevant to a commercial plant and refine startup, operations, maintenance, and safety procedures for use in future IGCC facilities. After the 5-year operations program, SCE has the right to purchase the plant from the other participants and operate it commercially for 15 years, subject to economic conditions and the necessary permits.

The IGCC technology being demonstrated at Cool Water offers several attractive features for utilities, including lower SO_x/NO_x emissions and solid wastes than those resulting from direct coal firing with stack gas scrubbing, less water and land use, potentially higher efficiency, and comparable capital and electricity costs. Further, the phased-construction approach of installing gas turbines, followed by combined cycles and coal gasification, offers many benefits and reduced risk (*EPRI Journal*, December 1985, p. 50). The short interval between expenditures and revenues minimizes the capital at risk. Rapid response to load growth changes means a better match between capacity additions and load growth. Its high availability/reduced reserve margin is noteworthy. And it can take advantage of temporary availability of low-cost oil or natural gas fuel.

A large group of utilities interested in the prospects of coal gasification for power generation have formed the Utility Coal Gasification Association. The association currently consists of 33 U.S. utilities, representing over half the generating capacity in the country, and 2 foreign utilities. The organization meets three times a year to review and discuss coal gasification progress and to exchange information on studies and plans for potential applications. A subgroup of 10 of these companies is conducting generation expansion analysis to identify the benefits of phased introduction of IGCC plants in their systems. Potomac Electric Power Co. has already projected benefits sufficient to warrant formal inclusion of a phased IGCC plant in its construction plan for commissioning in the mid 1990s. *Program Manager: Neville A. Holt*

COAL PYROLYSIS

EPRI recently undertook extensive research to evaluate the viability of coal pyrolysis products for utility use. The objectives of the studies were to evaluate the combustion and storage characteristics of pyrolysis char and to evaluate the upgrading potential of pyrolysis liquid products (tar). To achieve these objectives, it was necessary to produce sufficient quantities of the char and tar in a process unit large enough to produce commercially representative products. A Utah bituminous coal was selected for the feed coal because of its low-caking properties and its expected high liquid yield.

Pyrolysis is a coal-skimming process. During pyrolysis, the volatile matter of the coal is thermally removed in the form of gas and tar products. The remainder (and by far the largest portion) of the coal remains as a solid char product. In most pyrolysis schemes, this char product would be a replacement for coal in utility boilers. The tar, on the other hand, would be sold as a premium liquid product. The sale of this premium liquid product would reduce the cost of the substitute boiler fuel (the char) well below that of coal. Whether pyrolysis is economically viable for utility application depends heavily on the quality of the liquid product (i.e., whether it can be upgraded into a premium product). To provide a sufficient incentive for a utility to switch from coal to char, the market price of the liquid product must cover all the capital and operating costs associated with pyrolysis, all liquid-upgrading costs, all costs of substituting char for coal, and a credit for the utility fuel costs. In addition to these economic constraints, two technical constraints exist: the liquid product must be upgradable to a salable premium product, and the utility must be able to use char as a substitute fuel. Thus, there are two issues in considering coal pyrolysis for utility use: economic and technical viability. EPRI research addressed the latter of these issues.

Lurgi-Ruhrgas pyrolysis run

To evaluate the technical feasibility of pyrolysis for utility use, EPRI needed sufficient quantities of pyrolysis products for testing and upgrading. Further, these products had to be representative of commercially derived material. Thus, a sizable production run was needed in a pilot plant–scale unit. These constraints substantially narrowed the field of potential contractors. For both technical and availability reasons, EPRI selected the Lurgi-Ruhrgas (L–R) process for the production run (under subcontract to Bechtel Group, Inc., RP2505-2). The project was divided into three phases; a decision whether to proceed would be made after each of the first two phases.

In July 1984 two samples of Utah coal were delivered to the Lurgi mini-L–R pyrolysis facility near Frankfurt, West Germany. The samples were from the Wilberg and Deer Creek mines. Although in the small-scale test both coal samples produced char with higher ash content and lower volatiles than expected, the results were sufficiently positive to warrant proceeding to the operability run in the 10-t/d L–R pilot plant.

In August 1984 eight specially prepared shipping containers were loaded with a total of approximately 115 t of Deer Creek coal. Concurrent with coal transport, Lurgi modified the L–R pilot plant to allow processing of the Utah coal. (Previous plant work had been with oil shale, which has different handling characteristics and volatiles content.)

Plant operation was conducted in two sequential steps: a three-day run to demonstrate operability of the pilot plant and a nine-day production run to make the desired products. During the first run, coal was processed at pyrolysis temperatures ranging from 600 to 700°C. The volatile matter content of the char varied from 4 to 8%. (The contract actually called for production of two chars, one containing 3% volatiles, the other, 8%.) The operability test was completed on November 16, and authorization was given to proceed with the production run.

Other than pluggage problems early in the nine-day production run, ostensibly no other operating difficulties occurred. During that run, 83 t of Utah coal were pyrolyzed, producing 35 t of char. Operation at two temperatures produced char with two volatile contents, 5.5% and 8%. However, to keep the plant operating smoothly during the production run, Lurgi found it necessary to blend the middle and heavy tar products. Excessive carryover of solids into the liquid product stream (exiting the pyrolysis unit) necessitated the blending to make the heavy tar sufficiently fluid. Lurgi felt that the abnormally high solids carryover resulted from the fine nature of the Utah coal and also from a plugged cyclone, which might have removed some of the solids.

However, it may also be argued that high solids carryover is an inherent process problem. Compared with other pyrolysis processes (such as Toscoal), the L–R liquid yield is typically expected to be higher. However, this higher yield is in the form of heavy tar, contaminated with solids (viscous toluene-insoluble product and char dust). The upgradability of high-solids heavy tar is a key factor in the L–R pyrolysis technology. With the Utah coal, the solids carryover was even higher than expected; the tar contained 30% insoluble material. Technical and economic feasibility requires that this material be upgraded to a usable and/or salable product.

Liquid upgrading

Several contractors were to do the liquid upgrading. Two contractors were selected to use alternative processes for upgrading the L–R heavy tar: Lummus-Crest, Inc. (RP2505-5), using its L–C fining technology, and Veba Oel (RP2505-6), using its Combi-Cracking process. (The Combi-Cracking process also simultaneously hydrotreats the coal-tar-derived distillates.) Universal Oil Products, Inc. (UOP) was selected to hydrotreat the light and middle oils from the L–R process (RP2505-7), as well as the distillable material produced by Lummus. Unfortunately, none of these contractors received the anticipated products. The light oil was in the form of a light oil–water emulsion and the middle oil had been blended with the solids-laden heavy oil during L–R operation.

Immediately on completion of the production run by Lurgi, Veba Oel sent trucks to the Lurgi site to collect the middle and heavy oils for processing. Attempts to distill the middle-heavy oil blend into separate fractions were unsuccessful. Therefore, the whole feed was sent to the Combi-Cracking liquid-phase hydrogenation reactor. After extensive operational difficulties and plant modifications, Veba was finally able to convert the toluene-soluble portion of the heaviest (+500°C) tar. However, because of the excessively high toluene-insoluble content of the tars (50%), Veba was not able to produce meaningful quantities of upgraded product. Most of the converted material had to remain with the insoluble material to maintain viscosity limits for removal from the hydrogenation reactor.

Lummus was even less successful in its attempts to upgrade the heavy tars. A brief screening run in a stirred autoclave was planned to precede the L–C fining pilot plant run. One drum of the heavy oil was heated and a portion poured into the feed tank. The feed tank and all transfer lines were kept at elevated temperatures. Despite these precautions, the feed line plugged soon after operation began. All attempts to restart were unsuccessful. After thorough mixing of the contents in the heated drum of heavy oil, a sample was withdrawn for analyses (vacuum distillation, viscosity, quinoline insolubles). The analyses indicated that the material was 30% unconvertible quinoline insolubles. Thus, to produce two barrels of distillable product (75–90% conversion), about three barrels of quinoline-soluble feed would have to be processed. This material, however, would contain over 500 lb (227 kg) of quinoline-insoluble material. Even if pumped successfully to the L–C fining reactor, such a large quantity of solids would plug the product receivers and liquid-level-control valves, in addition to providing very little net upgraded product. Lummus made several attempts to decrease the quinoline-insoluble material in the heavy tar (e.g., settling, solvent extraction), but all attempts were unsuccessful. At this point, further work with the L–R liquid products was abandoned. The unsuccessful results with these liquid products indicate that utility use of coal pyrolysis products seems both technically and economically doubtful.

The upgrading of the light oil by UOP was to take place after receipt of the distillable material produced by Lummus. (UOP received no middle oil for upgrading because Lurgi mixed all of it with the heavy oil.) Because no such material was forthcoming, this effort was terminated. UOP did, however, perform some analytic work on the light oil–water emulsion. (For this material to be useful, a successful and economic method would have to be found to break the emulsion.)

Char utilization

Although the tar upgrading proved infeasible, the char characterization program was completed. Combustion Engineering, Inc., carried out a two-phase program to evaluate the combustion characteristics of pyrolysis char (RP2505-4). Proper char combustion characteristics are essential to the concept of substituting char for coal in boilers. Combustion Engineering performed bench-scale tests with a low volatile char (5.9%) and a higher volatile char (8.4%). Both chars had very high ash contents, 27–33%.

Bench-scale results on the Lurgi pyrolysis chars indicated both medium slagging potential and medium fouling potential. The potential for flame turndown problems also seemed likely with both chars. Bench-scale results indicate that the pyrolysis chars have marginal fuel properties and thus need larger-scale testing to determine whether they are acceptable as boiler fuel.

As a result of the bench-scale work, pilot-scale testing of the chars was completed recently. Preliminary results indicate that although no support fuel was required for firing, the operation suffered fouling problems and temperature limitations.

Research results

This work shows that coal pyrolysis is not a viable route for electric utilities to pursue. If the products that EPRI received from the L–R pyrolysis production run are truly representative of commercially derived material, utility use is neither technically nor economically feasible. In effect, an adequate fuel, coal, was turned into an unusable liquid and an only marginally acceptable coal substitute.

EPRI's cosponsors in the pyrolysis project were the State of Utah, Utah Power & Light Co., and Bechtel Power Corp. *Project Manager: Linda Atherton*

R&D Status Report
COAL COMBUSTION SYSTEMS DIVISION

Kurt Yeager, Vice President

POWER PLANT COOLING SYSTEMS

Research and development on heat rejection planned or under way in the Heat, Waste, and Water Management Program concern the primary types of steam-electric power plant cooling systems: wet-cooling towers, once-through cooling systems, cooling lakes and impoundments, and wet/dry cooling systems. A considerable fraction of the research effort focuses on closed-cycle wet cooling, primarily because over three-quarters of the steam-electric power plants being built have wet-cooling towers. The work centers on the prediction, testing, and improvement of the thermal performance of wet towers. A related environmental research area is the prediction and measurement of the spatial distribution of cooling-tower effluent—the visible plume and saline drift.

Evaporative cooling

Enhancing wet-cooling tower performance improves power plant economics by reducing turbine exhaust pressure. Recent surveys indicate that the majority of cooling towers in the United States are operating below required performance, or are "short," because utilities do not possess specific fill data and design information to accurately assess vendor bids for cooling towers. (The fill is the packing in the tower that enhances evaporation and thus cooling.) This information would help utilities predict the thermal and hydraulic performance of the fill, which in turn determines the performance of the cooling tower.

To reduce and/or eliminate future short towers, utilities need detailed cooling-tower fill data that will allow them to evaluate vendor bids more accurately. EPRI therefore constructed a well-instrumented, 1.5-MW (th) small-scale cooling-tower test facility at the Parish station of Houston Lighting & Power Co. (HL&P) to obtain these data (RP2113). Nowhere else in the United States does there exist such a facility to provide the utility industry with impartial cooling-tower fill data that can be the basis for confident design and construction of full-scale cooling towers.

This effort is being funded by EPRI and eight utilities—HL&P, Indianapolis Power & Light Co., Pacific Gas and Electric Co. (PG&E), Public Service Co. of Oklahoma, the Salt River Project, Southern California Edison Co. (SCE), Southern Company Services, Inc., and TVA.

Facility construction, shakedown tests, and instrument calibration have been completed. An intensive series of cross-flow performance tests was conducted on a variety of fills during the fourth quarter of 1985 and early 1986 (Figure 1). Tests of fills in a counterflow configuration are scheduled for 1986.

Related full-scale tests are also being performed in dedicated test cells at two HL&P plants (Clarke and Parish) to confirm the small-scale test results. Counterflow tests at the Clarke plant were performed in 1984 and 1985, and a series of cross-flow tests were carried out at the Parish plant in late 1985. These full-scale tests are providing the data to verify the methods of predicting performance that are being developed in this research.

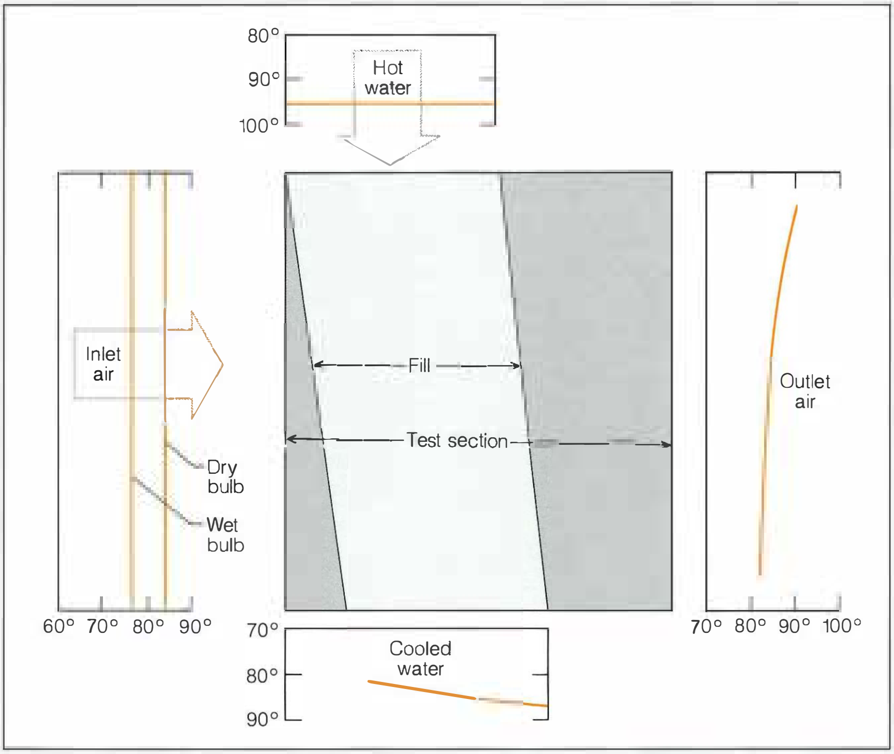


Figure 1 Sample results from cross-flow wet-cooling-tower tests. In this configuration hot water flowing down the fill in the test section is cooled by conditioned air flowing across the section. The graphs show inlet and outlet temperatures (in °F) for both the air and the water. (Ambient air temperatures were 74°F wet bulb and 81°F dry bulb.)

Three state-of-the-art computer codes are using these data in wet-tower performance prediction: VERA2D-84, developed for EPRI by CHAM of North America, Inc. (RP1262); FACTS, developed by the Norris Engineering Laboratory of the Tennessee Valley Authority (TVA); and TEFERI, developed by Electricité de France. In an associated effort, Robert D. Mitchell, a consultant, is evaluating the VERA2D-84 code for its accuracy and sensitivity to variations in input data (RP1260-46).

The project plan also includes studying factors that degrade cooling-tower performance (fill degradation, icing, nonideal fan performance, and wind effects), as well as improving the measurement of air flow rate and the measurement of flow rate in large-diameter circulating-water pipes.

Numerous reports will be forthcoming this year that will summarize each small-scale cooling-tower fill test. Other reports to be issued will cover specific topics, such as tower specification and bid evaluation, retrofit design, and performance testing of cooling towers. Later, all these reports will be incorporated into a design manual to aid utility engineers in cooling-tower design and operation.

In studies of the environmental effects of wet-cooling towers, the emphasis is on the visible plume (a potential source of icing, shadowing, and fogging) and on deposition of saline drift (a potential source of corrosion and of injury to vegetation). Argonne National Laboratory, the University of Illinois, and the University of Chicago have developed a computer code (CS-3403-CCM) capable of predicting both the trajectories of plumes and the deposition patterns of drift from single and clustered towers (RP906-1). A follow-on effort to provide user assistance and to document user experience is in progress (RP906-3).

Once-through cooling

EPRI research on once-through cooling is focusing on reducing fish entrainment and impingement at intake structures. This impingement can become so severe that plant operation can be impacted to the point of shutdown. On the basis of a study completed in 1984 (CS-3644), EPRI has undertaken a four-year (1985–1988) effort to evaluate the performance of behavioral barriers for diverting fish at cooling-water intake structures (RP2214). Three behavioral barriers—poppers (pneumatic air guns), air bubble curtains, and strobe lights—will be tested individually and in combination at four plants that are representative of different source water environments (lake, river, estuary, and ocean).

Ontario Hydro's Pickering station, on a freshwater lake, was selected as the first test site. Because the Pickering station was the site for previous intake system research funded by Empire State Electric Energy Research Corp. (Eseerco), complete control and test structures were in place, and an extensive data base on seasonal fish populations was available. Testing at this site began on July 1, 1985, and continued through August 23; additional testing will be conducted from May 1 through June 30, 1986.

Figure 2 shows the site 1 control and test structures, which can be alternated. The structures are basically pilings for mounting the behavioral barriers and fish nets. Investigators conduct experiments at two-hour intervals, after which they raise the gill nets and wing nets to determine the fish catch. The fish are sized and counted, and their location and direction in the nets are recorded. These data are then analyzed in association with information on fish life stage, current velocity, water temperature and turbidity, and surface weather conditions.

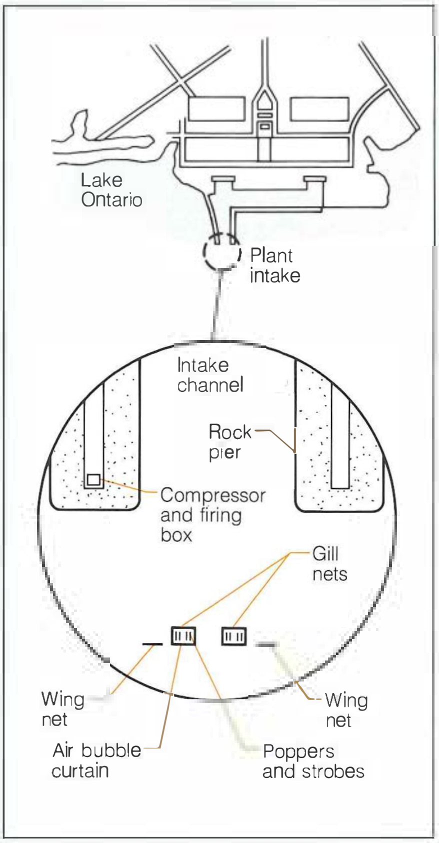


Figure 2 In this fish diversion system being tested at Ontario Hydro's Pickering station, two structures beyond the plant intake channel are equipped with three types of behavioral barriers—poppers (pneumatic air guns), strobe lights, and air bubble curtains. In a given test, barriers on one structure are activated and the other structure serves as a control. Then, to assess the barriers' effectiveness, researchers count the fish caught in nets beside and along the back of the structures.

In addition, a hydroacoustic census system (sonar) assesses the extent of fish repulsion attributable to each deterrent by measuring the number and distribution of fish echoes.

Four sets of tests have been completed—popper, popper with air bubble curtain, air bubble curtain, and air bubble curtain with strobes. Preliminary results indicate that poppers used individually were very effective in diverting adult alewife (the area's primary fish species). Over a three-week period, approximately 73% fewer fish were collected in the test structure than in the control structure. Further, hydroacoustic data show that the range of influence for poppers is at least 5 m (16 ft).

Test results for the air bubble curtain were less dramatic. When used alone, the air bubble curtain was basically ineffective. When backlit with strobe lights, the air bubble curtain proved more effective, but still less so than poppers. When poppers were combined with an air bubble curtain, the diversion efficiency of the poppers dropped significantly; investigators speculate that the air bubble curtain may muffle the effect of the poppers.

Plans for 1986 field testing at the second site (Central Hudson Gas & Electric Corp.'s Roseton station) are well under way. At site 2, the river site, testing will be different from testing at the Pickering station in several respects. First, testing will be accomplished in two separate stages, spring (March–April) and fall (August–November). Second, the fish species will be different and more varied. Third, the entire intake structure will be used for alternately collecting experimental and control data, whereas at site 1 side-by-side tests were conducted simultaneously. Fourth, the popper may be replaced with a mechanical hammer, a new device developed jointly by Ontario Hydro and Eseerco. The hammer works on the same principle as the popper but is considered to be more reliable operationally. In addition, its frequency can be adjusted prior to installation, which may improve its selectivity for diverting certain species.

This project is cofunded by three utilities, Central Hudson Gas & Electric Corp., Ontario Hydro, and SCE. Additional cofunders are being sought.

Cooling lakes and ponds

Current EPRI research on cooling lakes and ponds centers on improving hydrothermal performance through an improved understanding of evaporation and through improved geometric design (RP2385). In an early phase of the project, Massachusetts Institute of Technology (MIT) and a team of other researchers measured evaporation from a small, heavily instrumented experimental pond by a variety of techniques. Data from this and related test programs showed that existing formulas are sufficient to correlate data on evaporation rate when appropriate mathematical models are used in data interpretation (CS-2325). In 1984–1985, these investigators performed field tests to extend the applicability range of the existing formulas for evaporation rate in hot ponds of simple geometry at the Savannah River plant operated by DOE. In conjunction, MIT conducted laboratory experiments and mathematical model studies to improve intake and discharge designs. Both a decrease of about 10% in construction and operating costs and increased pond siting flexibility are projected in these studies. Final project documentation, which includes reports on the field tests, laboratory experiments, and numerical model simulations, is in progress.

Wet/dry cooling

R&D is also being performed to identify, assess, and demonstrate dry and wet/dry cooling technologies that offer a substantial economic benefit compared with existing commercial systems for utilities forced to use water-conserving cooling systems.

The demonstration of an ammonia phase-change heat rejection system has been in progress since 1982. The 17-MW (th) advanced concepts test (ACT) facility is situated at PG&E's Kern station in Bakersfield, California (RP422). EPRI and four utilities (PG&E, SCE, Los Angeles Dept. of Water & Power, and the Salt River Project) are sponsoring the project. Battelle, Pacific Northwest Laboratories has operated and tested the facility, with assistance from Union Carbide Corp.

Much of the recent testing focused on the capacitive cooling system, which provides supplemental cooling for the ammonia loop without evaporating water (*EPRI Journal*, December 1985). During periods of high ambient temperature and peak electrical demand, water is circulated through a water-cooled steam condenser, which condenses some of the steam from the turbine. The heated water is pumped to the top of a water tank, where it stratifies above the cooler water, as in a domestic water heater. The thermocline (the interface between the hot and cold water) moves down the tank as more steam is condensed. At night, when the ambient temperature falls and electrical demand is less, the cooling tower has excess capacity. The chill operation is then begun. Warm water in the water tank is pumped to a chiller unit, where the water is cooled during the process of boiling ammonia, and is then returned to the bottom of the water tank. The thermocline moves up the tank as more ammonia is boiled. The ammonia vapor is then compressed to the primary ammonia loop pressure, and heat is rejected from the cooling tower to the atmosphere. The water tank thus behaves as a thermal capacitor.

The primary advantage of the capacitive cooling system is that it provides supplemental cooling at the time of peak electrical demand but does so without consuming (evaporating) water. It thus operates in a zero discharge mode, an advantage from an environmental standpoint. The capacitive system has an economic advantage over methods of augmentation cooling that evaporate water, but only when water is very scarce.

In the capacitive system tests, the steam flow divided efficiently and continuously between the water-cooled condenser and the ammonia-cooled condenser-reboiler. No significant pulsations or periodic flow imbalances occurred. The maximum measured heat duty of the system agreed with the design value to within 5%. The static behavior of the thermocline as a function of time is a good indicator of stratification. It was found that the gradient of the thermocline was essentially unaffected over a seven-day period, although the warm section lost heat and the cold section gained heat, as expected. (The tank was not insulated.)

In intermittent operation over three years, the demonstration facility logged about 1500 hours of operating time. The overall system performance proved to be reliable, with the exception of two ammonia circulation pumps in which a number of seal and bearing failures occurred during facility startup. The last seven tests, however, were conducted without incident, and the Kern power plant staff operated the system with minimal guidance.

During the test program, the system operated safely, with the exception of an ammonia leak early in the operation phase, caused by improper gaskets that have since been replaced. System operability has been excellent, with the cooling loop smoothly following plant load variations. Recently, a steam turbine trip caused an electrical loss to the cooling system, but the system was shut down safely. Flow oscillations in the ammonia loop, the only problem with operability, resulted during cool weather conditions, when ammonia subcooling occurred. In a future system this problem can be readily solved through heat exchanger redesign in which a more positive condensate drain system would be incorporated.

In summary, the primary goals of the demonstration have been met—the system operates safely and reliably, and it responds satisfactorily to the operational fluctuations of a power plant. To date, no significant corrosion, fouling, or erosion has been observed. *Subprogram Manager: John A. Bartz; Project Manager: Wayne C. Micheletti*

SHAWNEE AFBC DEMONSTRATION

The atmospheric fluidized-bed combustion process (AFBC) mixes solid particles of fuel (coal) and sorbent (limestone) at atmospheric pressure during combustion. Sulfur in the fuel reacts with calcium in the sorbent, thus reducing the emission of sulfur dioxide in the flue gas. An additional potential benefit of the technology is greater flexibility in choosing and changing fuels over the life of a power facility. After bench-scale testing and operation of a 20-MW pilot plant, the technology is now ready for demonstration at utility scale. Accordingly, the Tennessee Valley Authority (TVA), in cooperation with DOE, Combustion Engineering, Inc., the state of Kentucky, Duke Power Co., and AFB Development Corp., has under construction one of three EPRI-sponsored demonstration projects: a 160-MW retrofit AFBC boiler. EPRI is providing technical and financial assistance.

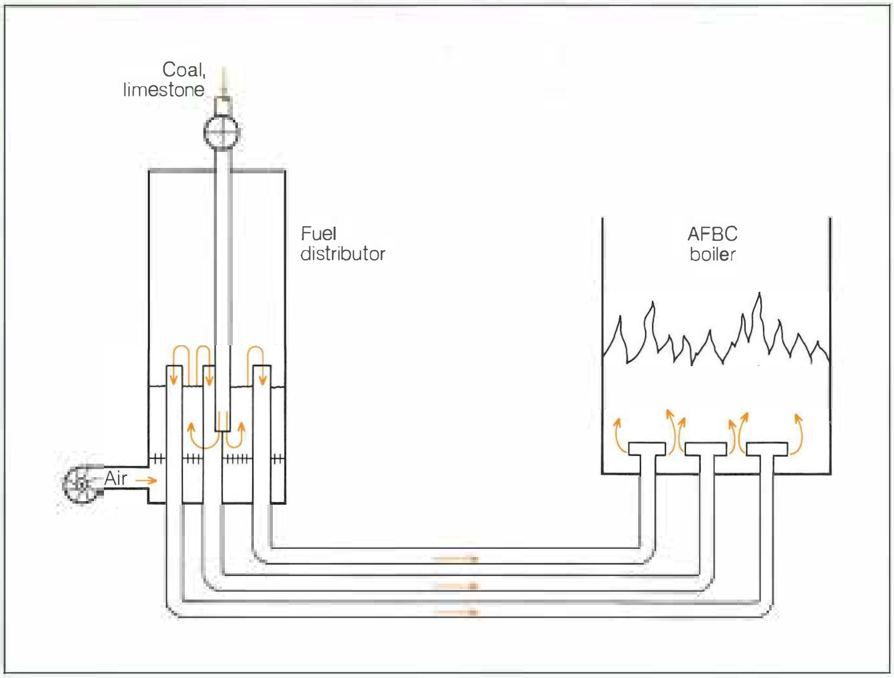
The AFBC process has been under development for steam generators since the 1960s. The petroleum industry initiated the technology and used it in the catalytic cracking of feedstocks. Electric utilities became involved later. One of the reasons for utility interest was the change in air emission requirements. This technology is attractive because it allows coal to be burned with relatively low emissions of sulfur dioxide and nitrogen oxides.

The technique entails mixing a sorbent, such as limestone, with coal to create the combustion bed. Residence time in the bed and an in-bed heat exchanger, which controls the temperature, enable the calcium in the sorbent to capture the sulfur as calcium sulfate.

Bed temperature is also the key to reduced emission of nitrogen oxides because at 1550°F (850°C) nitrogen in the air will not readily combine with oxygen. Low bed temperatures also contribute to greater fuel flexibility. A wide range of fuels can be burned because at low temperature slagging and ash properties are not a concern.

TVA's Shawnee steam plant, the location of the demonstration boiler, is on the Ohio River 10 miles (16 km) northwest of Paducah, Kentucky. The 10-unit plant was built in the 1950s and uses river water in its once-through condenser cooling system. Its particulate collection system was upgraded in the early 1970s by the addition of electrostatic precipitators and in the 1980s by the addition of baghouses and two tall plant stacks to service all units. Shawnee is also the location of the 20-MW

Figure 3 The underbed feed system for the TVA 160-MW AFBC demonstration boiler has 12 fuel distributors like the one shown here. A blower is used to pressurize each distributor and transport the fuel-sorbent mixture through outlet lines (10 total per distributor) to the AFBC boiler.



AFBC pilot plant, sponsored jointly by TVA and EPRI.

When completed, the new 160-MW AFBC boiler will replace the existing Unit 10 boiler. Steam from the new AFBC boiler will be piped to the existing turbine. All the present turbine cycle components, including the condenser, feedwater heaters, and feedwater pumps, will be retained. The plant will continue to generate 160 MW of electricity.

The AFBC boiler, being designed and fabricated by Combustion Engineering, will generate 1,100,300 lb/h of steam at 1833 psig and 1003°F (139 kg/s at 12.8 MPa and 540°C). Steam exhausted from the high-pressure turbine will be reheated to 1003°F.

The AFBC boiler will be a balanced-draft, bubbling-bed design. At full load it will burn approximately 65 t/h (16 kg/s) of coal and use 23 t/h (5.8 kg/s) of limestone. Kentucky No. 9, a high-sulfur bituminous coal available nearby, will be the predominant coal used; it is much less costly than low-sulfur coal, which otherwise would have to be burned to obtain the reduced sulfur emissions. Boiler efficiency is guaranteed to be greater than 87.5% at full load, and the calcium-to-sulfur molar ratio is 2.3 for 90% sulfur capture.

To accomplish good boiler turndown, the furnace of the unit is divided into six independent firing zones. This allows smaller increments of the boiler to be shut down to reduce load. Bed temperature is kept at 1550°F (850°C) for optimal sulfur capture by means of an in-bed heat exchanger that contains both superheater and evaporative tubes. Additional superheater surface, as well as the economizer and reheat surface, is contained in the convection pass.

Coal enroute to the silo is crushed to ¼ in and dried to less than 6% moisture by hot flue gas. Limestone and coal are fed from their silos through a system of gravimetric feeders and surge hoppers to 12 fuel distributors. Each distributor is a fluidized "bottle" with a central inlet and 10 outlet fuel lines arranged around the inlet (Figure 3). Fuel transport blowers pressurize the bottles to carry the coal-sorbent mixture to the furnace. Each firing zone is fed by two bottles.

After the convection pass of the boiler, flue gas and particles enter cyclone dust collectors that capture and recycle unconsumed fuel and sorbent. This recycling improves both boiler efficiency and sulfur capture. Flue gas then enters the baghouse.

The conceptual design of the demonstration plant has been completed, and detailed design is in progress; construction began in late 1985. First fire and startup are scheduled for spring 1988 and will be followed by a four-year test program that includes shakedown and parametric testing. The unit will then be operated for at least six years to demonstrate the economics of AFBC technology.

The current cost estimate for the project is $205 million; this figure includes the capital cost and the costs of the test program.

The main purpose of the project is to successfully demonstrate the economic and environmental performance of a utility-size AFBC boiler connected to a utility grid. Cost and reliability will also be monitored and fuel flexibility demonstrated, as follows.

- The TVA 160-MW demonstration plant has been designed specifically for Kentucky No. 9 coal. It will be important to test the fuel flexibility of this particular unit and, by extension, that of large-scale AFBC technology in general.
- As the final step in a fuels characterization project, 160-MW operation on the performance coal, as well as on alternative fuels, will link small-scale with large-scale test results. The large-scale testing, it is hoped, will validate the fuels characterization approach currently under development.
- The purpose of monitoring capital costs, O&M costs, and equipment reliability of the demonstration plants is to develop the required data for evaluating future commercial AFBC plants and minimize the uncertainty associated with cost estimation.
- During construction of the three AFBC demonstration plants, capital costs (e.g., materials, labor, engineering, and overhead) are being monitored in a consistent manner and format to facilitate plant comparison. Documentation will be done in such a way that future technology developments and changing economic conditions can be easily incorporated.
- Once the plants begin operation, O&M costs will be monitored on a continuous basis. The data gathered will form the basis for estimating fixed and variable costs for O&M, fuel, and other consumables for future AFBC plants.
- EPRI plans to monitor the reliability of all plant components and to determine their critical operating conditions; the results will help set up optimal maintenance schedules. Reliability data will be compatible with existing reliability evaluation tools (e.g., UNIRAM) and data bases (e.g., the North American Electric Reliability Council's generating availability data system) and can be used for evaluating power plant designs.

Utility development of AFBC technology has been active since the 1960s. In 1988 it will take a giant leap forward when TVA's Shawnee Unit 10 comes back on-line with a new AFBC boiler. *Project Manager: C. C. Lawrence III*

R&D Status Report
ELECTRICAL SYSTEMS DIVISION

John J. Dougherty, Vice President

OVERHEAD TRANSMISSION

Wood pole strength assessment

In a cooperative program between utilities and a destructive wood pole testing laboratory, researchers have been assembling data on the strength of in-service wood transmission poles (RP1352). The goal is to gather sufficient destructive testing data so that a positive correlation can be established between these data and field sonic test data on the same poles; this will enable utilities to assess the strength of similar poles. The Structural Engineering Laboratory of Colorado State University has been working with Engineering Data Management, Inc., to gather and analyze the data.

Before destructive testing, the poles are subjected to both first- and second-generation sonic nondestructive evaluation (NDE) procedures; the aim is to develop NDE as a viable tool for in situ evaluation of existing poles. The cost to utilities is $250 a pole, plus shipping to Fort Collins, Colorado. This cost covers the actual testing of the pole and represents about one-third of the per-pole cost for the total task.

The first poles provided by utilities for this program were tested in July 1985, and to date more than 100 poles have been tested. The work has resulted in two breakthroughs that can help utilities assess the structural capability of in-service wood pole lines.

Of immediate usefulness to utilities involved in the test program is the application of strength data on new poles. By comparing data from the EPRI new-pole data bank with the data collected on a utility's old poles, a determination of the poles' rate of deterioration can be made. (Figure 1 shows an example.) This information is of value in managing wood pole lines and assessing their reliability.

The second program breakthrough resulted from the application of second-generation NDE procedures to in-service wood poles. In Figure 2 NDE predictions based on measurements made at the groundline of a set of in-service poles are compared with data on actual pole strength obtained in full-scale laboratory tests. The close correlation indicates the ability of second-generation NDE procedures to predict the in situ strength of individual wood poles. These procedures promise to provide a heretofore unavailable means for utilities to evaluate the strength of in-service wood poles and to manage their wood pole lines in an efficient, cost-effective manner. Field applications of the new NDE technology are planned during 1986, and it is now available for trial use by utilities. *Project Manager: Paul Lyons*

Transmission line optimization

About one year ago EPRI released the computer program TLOP (transmission line optimization), developed under RP2151. First and foremost, TLOP is a program for conductor selection, which is perhaps the most important decision a transmission line designer makes. The total lifetime cost of a line is largely determined by which conductor is selected. To make this decision, one must take into account over 200 parameters that describe requirements and limitations.

Of course, the computer is ideally suited to considering many variables and drawing a conclusion on the basis of a preprogrammed methodology. TLOP takes into account all the parameters referred to above. Some of these input parameters are fixed as requirements. For others, ranges are specified so that the program can search for the best value within the range. One can set limits for radio interference, electric fields, voltage, power transfer, number of angle structures, type of structure,

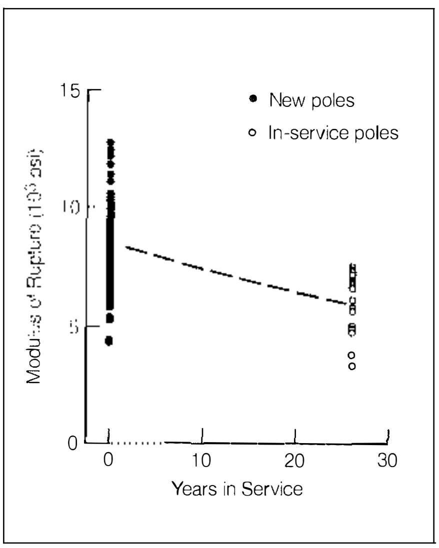


Figure 1 The average decrease in the modulus of rupture at groundline for in-service southern pine transmission poles is quite gradual, as indicated by this comparison of data on new poles with data on older poles collected in RP1352.

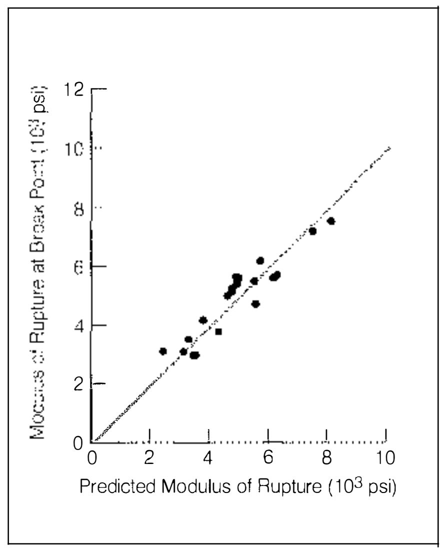


Figure 2 Comparison of measured pole strength (at the break point) and strength as predicted from groundline NDE measurements for 20 poles. The standard deviation for the group was just 600 psi (4137 kPa).

and many other parameters, for example, and then establish ranges for conductor systems and average span length. Some input parameters that were initially fixed, such as the cost of aluminum or the cost of money, can be varied in a sensitivity analysis to examine "what if" questions. The program is very flexible, giving the design engineer ample opportunity to make judgments on the basis of experience.

TLOP performs many subfunctions that are necessary to achieve the main goal of conductor selection. These include calculating sag and tension, radio interference, audible noise, electric fields, and conductor temperature, as well as direct and lifetime costs. These functions can be useful at different stages in a project—so useful, in fact, that it has been decided to break some of them out into stand-alone programs for quick and easy application. Also, TLOP and these stand-alone functions are being incorporated into the TLWorkstation* format. To make life a little easier for the nonexpert user, a new executive program has been written for the TLWorkstation system so that all programs in the system will have a common format.

After three seminars and a year's use of TLOP by several utilities, EPRI has had a lot of feedback suggesting ways to improve the program. Almost all these suggestions have been adopted, and version 1.5 has been issued. Perhaps the most important improvement is the replacement of cost algorithms with mini–design subprograms for structures and foundations. The cost algorithms were difficult to implement for cases different from the base cases and could give incorrect answers if inadvertently used outside the range of parameters for which they were designed. The mini–design subprograms are easy to use and apply over the full range of input parameters.

Another big improvement in TLOP version 1.5 is the addition of wood pole design capability. Both single wood pole structures and H-frames are covered. Because wood is the most popular structural material, the inclusion of this capability will greatly increase the usefulness of TLOP.

TLOP calculates both the first cost and the lifetime present worth of revenue requirements (PWRR) for any configuration analyzed. Usually the configuration with the lowest PWRR is not the one with the lowest first cost. How does one go about choosing between them? To help with this judgment, version 1.5 includes a break-even analysis in the output activity. By using this capability, one can compare two alternative conductor systems on a year-by-year basis. For instance, conductor *A* might be the lower-cost alternative in years 1 through 23, whereas conductor *B* is lower in years 24 through 35. The base case analysis would show conductor *B* to have the lower PWRR; but personal judgment might lead one to conclude that, given the uncertainties about conditions 24 years hence, the correct choice is the system with the lower first cost.

TLOP version 1.5 features many other changes that users will welcome, but there is not enough space to describe them here. It is important to note, however, that the first issuance of version 1.5 is for the IBM PC or similar microcomputers. It is necessary for the user to have the hard disk and math coprocessor capability of the XT or AT adaptation, as well as 640K of random-access memory. Other versions for the IBM mainframe, the VAX and Prime minicomputers, and the Cromemco microcomputer will follow. TLOP version 1.5 is being issued concurrently with TLWorkstation version 1.0 and can be obtained separately or as part of the whole TLWorkstation package. *Program Manager: Richard Kennon*

*TLWorkstation is an EPRI trademark.

DISTRIBUTION

Amorphous steel core distribution transformers

In 1983 EPRI and the Empire State Electric Energy Research Corp. cofunded a project with General Electric Co. to develop a commercially feasible distribution transformer having an amorphous metal core (RP1592). The project is progressing on schedule, and to date General Electric has accomplished the following: selection of a cost-effective design for the core and coil; establishment of a pilot manufacturing facility for amorphous core distribution transformers; and construction of 1000 25-kVA, 15-kV transformers.

The 1000 transformers have been shipped to over 90 utilities for a two-year field trial program. These utilities are being asked to make yearly core loss (watts) and exciting current measurements on the transformers to determine if these parameters vary because of changes in the amorphous core.

Utilities should find amorphous steel core transformers very attractive. From external appearances, they do not differ from silicon steel core transformers, and they can be handled and electrically loaded in the same way. However, electrical losses will be lower with the new transformers—core loss will be reduced to 60–70% of that of silicon steel core transformers. For the 1000 25-kVA units produced, the core loss was 25 W or less.

In the future all utilities may find the use of amorphous steel core transformers to be cost-effective on the basis of an evaluated-loss comparison. At this time the transformers may be attractive to only those utilities that have high costs assigned to losses; however, as the cost of amorphous metal drops and further refinements are made in the manufacturing process, more utilities may find the new transformers cost-effective. *Project Manager: Harry Ng*

Copper corrosion in conduit

A substantial portion of underground distribution cable is installed in conduit. Although the cable-in-duct system offers a degree of flexibility for cable repair and replacement and system growth, it has not been as free of corrosion as originally expected. In fact, some utilities have begun to report severe corrosion of copper concentric neutral (CN) conductors in conduit. Hence a project was initiated to determine the causes of this corrosion and to develop methods of protecting against it (RP1771). A secondary objective of this project was to develop a method of determining the degree of corrosion.

As expected, the principal cause of corrosion is cell action resulting from the accumulation of water, or mud and debris, in the conduit after the circuit has been in use for some time. In some cases the rate of CN corrosion may increase by as much as a factor of 20 when various concentrations of chlorides and sulfides are present in the accumulated soil. Also, laboratory tests combining imported backfill with clayish soils found that the corrosion rate of copper CN wires increased by a factor of 10. This is corroborated by the results of a previous project published in 1982 (EPRI EL-1970).

Tin and alloy coatings on the CN wires may also contribute to CN corrosion because of galvanic action between these alloys and the copper substrate. Hence it is recommended that only bare copper CN wires be used for conduit installation if the utility must use bare CN cable. Otherwise, jacketed cable is recommended.

Two actions can be taken to prevent undue corrosion in new or replacement cable installed in duct. One is to simply use jacketed cable; the other is to apply corrosion inhibitors and seal the ends of the conduit after installation. The final report for RP1771 will describe several inhibitors that effectively control corrosion and will discuss laboratory tests of various conduit seals. Although effective, neither of these preventive measures seems practical for application to already-installed cables because of the difficulties involved in flushing and sealing the conduits.

A very important result of this project was the confirmation that moderate to very severe corrosion can be detected by a four-terminal resistance meter connected between two locations where the CN wires are accessible. Although this resistance method is not sensitive enough to detect very slight or beginning corrosion, it is the only positive method of determining that moderate to severe CN corrosion has occurred in cable in conduit. The final report for this project should be available by mid 1986. *Project Manager: T. J. Kendrew*

TRANSMISSION SUBSTATION

Low-cost gas-in-oil detector

When abnormalities occur inside transformers, gases are usually generated in the insulating oil. For example, if arcing occurs, it tends to generate hydrogen, and if the cellulose insulation overheats, carbon monoxide is usually given off.

The object of a project with Westinghouse is to develop a low-cost detector that can distinguish between carbon monoxide and hydrogen and give early warning of internal transformer distress (RP2445). The design that has evolved uses a permeation cell (developed under RP748) that allows gases to diffuse from the oil through a diaphragm and into a collection cavity (Figure 3).

The gases are then periodically exhausted past metal oxide sensors to the atmosphere. During this process, oxygen is depleted from the metal oxide sensors, varying their resistivity. The resistivity change varies, depending on the type of gas to which the sensor is exposed. The sensitivity of the detector has been arranged to indicate 100–500 ppm of hydrogen or 500–3000 ppm of carbon monoxide.

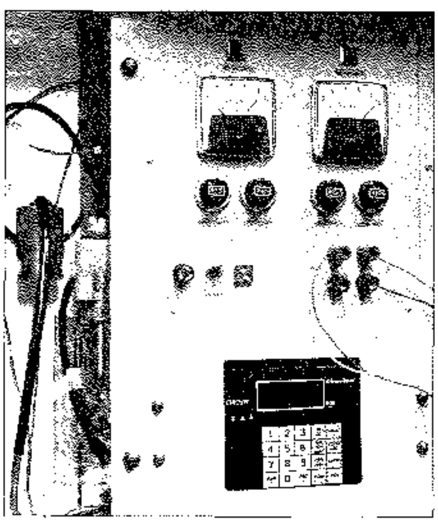


Figure 3 This low-cost gas-in-oil monitor has been developed to detect hydrogen and carbon monoxide in transformer oil. Excessive quantities of these gases indicate arcing or overheating of either the oil or cellulose. The permeation cell and sensor are on the left, and the electronics are on the right.

Two prototypes were constructed and tested under laboratory conditions. Ten units will be produced for field evaluation. Of particular concern will be the effects of extremes in temperature or humidity and the ability of the system to maintain its reliability by self-checking any malfunctions. Utilities interested in obtaining cells for field evaluation should contact the project manager. *Project Manager: Selwyn Wright*

POWER SYSTEM PLANNING AND OPERATIONS

Array processors for power flow calculations

Many static and dynamic power system computations are based on power flow calculations. In recent years utility engineers have experienced increased difficulty in acquiring the number of power system simulations needed to solve today's complex problems. The difficulty arises from the large amount of computer time required for so many simulations, the shortage of computer storage, and cost limitations. Further, when a utility's corporate computer is used for engineering planning studies, financial and other nonengineering tasks often take priority over engineering computations. Thus engineers need access to other, improved computation facilities if they are to obtain solutions in a timely, cost-effective manner. Similar problems exist in real-time applications because many energy control center computers are fully utilized.

Fortunately, computer hardware has undergone many changes in the last several years, involving new architecture, improved computation speeds, and reduced equipment costs. One example is the array processor—a low-cost peripheral device that can be attached to a general-purpose (host) computer. EPRI contracted with Boeing Computer Services, Inc., to determine the applicability of array processors to power flow computations (RP1710).

Boeing restructured the Bonneville Power Administration power flow program to run efficiently on an array processor. (This restructuring has also improved the execution efficiency on sequential computers.) Then the modified program was tested on a DEC VAX 11/780 computer and two Floating Point Systems array processors, the FPS-164 and the FPS-264. Time results were obtained for both the solution portion and the complete run (including input and output). Four test cases, ranging from 49 to 1450 buses, were used.

For the solution portion, both array processors were faster than the VAX—the FPS-164 ran 10 to 22 times faster and the FPS-264 ran 33 to 47 times faster. However, the Newton-Raphson solution typically represents only 15–30% of the total power flow run time. For the total run, no significant time saving was achieved with the FPS-164, while the FPS-264 ran four to six times faster than the VAX.

In view of these results, it is hard to justify the use of the FPS-164 for the power flow problem. However, the FPS-264 does appear attractive from the standpoint of run time. Other considerations, including the coordination of two machines and their respective operating systems, may offset the speed advantage of the FPS-264. The final report for this project will be available in April. *Project Manager: John Lamont*

Uncertainty and risk in electric resource planning

In the past the number of resource options available for system expansion was relatively small, and it was possible to forecast load growth and operating costs on the basis of historical records. Today, however, the options to be considered in system planning are affected by a number of constraints. Many of the technologies being considered are new, and their projected capital and operating costs are uncertain. Also, forecasting load growth and fuel costs has become difficult. Some of the advanced-technology options may not be economically feasible, and others may not be feasible for regulatory reasons.

The electric power industry has developed a variety of methods and computer programs to help system planners make sound decisions under these constraints and uncertainties. However, all these methods have a number of limitations, and they have not been developed to include risk. Recognizing the needs of system planners in this area, EPRI initiated a 20-month project in July 1985 with Power Technologies, Inc. (RP2537).

The objectives of this project are to identify the sources of technologic and economic uncertainties; to develop a suitable method for evaluating the technical and economic effects of various sources of risk on electric resource alternatives; and to integrate the sources of uncertainty into a decision analysis method.

The contractor is expected to develop a computer model that can address the sensitivities of electric resource options to various financial, regulatory, and technologic uncertainties. The model is also expected to provide the flexibility necessary for modifying resource plans in response to changes in load forecasts, fuel costs, and supply alternatives. *Project Manager: Neal Balu*

R&D Status Report
ENERGY ANALYSIS AND ENVIRONMENT DIVISION

René Malès, Vice President

EMISSIONS FROM POWER PLANT COOLING SYSTEMS

Chlorine (Cl_2) is commonly added to power plant cooling water to control biofouling. Its by-products rapidly react with ammonia (ubiquitous in natural waters) to form several compounds, some of which could adversely affect the environment. EPRI has therefore conducted a study to develop methods to measure these products of chlorination in the atmosphere and in receiving waters (RP1744). Several power plant cooling systems have been used to test and demonstrate the methods and acquire first estimates of concentrations.

Whether a power plant uses cooling water in a once-through system or uses an evaporative recirculation system, such as a cooling tower and/or holding pond, biofouling control is commonly necessary for efficient operation. An estimated 10^7–10^8 kg (10,000–100,000 t) of chlorine are used each year for this purpose. The chlorine is reduced to chloramines, haloorganics (mostly trihalomethanes), and nontoxic chlorides. Chloramines may be hazardous to aquatic organisms, and haloorganics may be a public health concern. Consequently, EPRI commissioned SRI International to characterize and measure emission of chlorinated organics from selected power plant cooling systems.

In a typical cooling tower, hot water (about 50°C) from the power plant condenser is pumped to the top of the tower, from which it cascades downward through an extensive grid system. In a forced-draft tower, ambient air is forced through this descending water by large fans situated at the top of the tower. Fans are not necessary in a natural-draft tower because the tower is designed to draw air through the structure. Both types of towers are designed to maximize evaporation and minimize the entrainment of the falling water into the draft. The cooled water collects in a basin at the bottom of the tower and then returns to the power plant condensers.

In many plants, the water is chlorinated from one to three times a day for periods of 20 to 120 minutes. Other plants use continuous but lower-dose chlorination. The buildup of dissolved and suspended matter in the evaporative system is controlled by the continuous removal of the recirculating water (blowdown). This loss is offset by the addition of fresh water (makeup feed).

Thus, emissions from a cooling tower can take two forms: emissions into the atmosphere as a result of cooling tower draft and emissions into receiving waters as a result of tower blowdown.

Sample collection

Grab samples of the recirculating water were fairly easy to collect. It was essential, however, that the collected water fill the sample container completely, leaving no headspace (to avoid the loss of volatile haloorganics before the water could be analyzed). A quenching agent was added to prevent further reaction with chlorine.

Collecting atmospheric samples (from the cooling tower plume) was much more difficult because of the large quantities of water droplets (drift) and condensing water vapor. There were two problems. The first was the difficulty of collecting samples that accurately represented the atmospheric emissions from the cooling towers. This problem was minimized by first evacuating each sample vessel, slowly backfilling it with sample atmosphere, and then repeating the process to make sure the inside walls were passivated.

The second problem was in analyzing for very low concentrations ($<40\ \mu g/m^3$, or less than 5 ng/g) of haloorganics in the presence of a large amount of water. Thus finding a method for collecting atmospheric organics without water entrainment was a major project goal. The successful design is a modification of EPA's Method 5.

The less-volatile organics were collected at the same flow rate as that in the tower draft by using an XAD-2 trap. XAD-2 is an organic resin that is considerably more efficient at absorbing organics than at absorbing water. It is therefore able to accumulate (concentrate) organics, which are extractable by solvents for subsequent chemical analysis. A series of cooled impinger traps collects entrained water, giving a measure of the concentration of water in the plume. The last trap in the impinger train contains a desiccant to protect the vacuum pump.

Volatile organics were collected to minimize water entrainment by facing the probe opening away from the tower draft. In this case, Tenax sorbent traps were used. Tenax performs similarly to XAD-2 except that it absorbs volatile organics more efficiently. However, for very volatile species, such as chloroform ($CHCl_3$), even Tenax is not a very efficient collector, and trap breakthrough often occurs. Laboratory tests determined trap breakthrough volumes. By using low-flow (100 cm^3/min) and low-volume (1000 cm^3) collection to avoid trap breakthrough, volatile atmospheric emissions were collected successfully.

Analysis and modeling

Standard procedures of gas chromatography (GC), mass spectrometry (MS), and amperometric titration were used to analyze recirculation water for haloorganics and residual chlorine. (Residual chlorine refers to the oxidant remaining after the addition of chlorine to water. Examples of residual chlorine species are Cl_2, HOCl, OCl^-, and inorganic and organic chloramines. Note that the chloride ion, Cl^-, is not a residual chlorine species.)

Analysis of atmospheric emissions requires desorption from Tenax and XAD-2 traps for volatile and less-volatile haloorganics, respectively. Volatile organic species are effectively thermally (200°C) desorbed from Tenax sorbent, but less-volatile organics are extracted from XAD-2 with an appropriate solvent (e.g., dichloromethane, CH_2Cl_2). Analysis of extracted or desorbed material is by GC; detection is by electron capture, electrolytic conductivity, or MS. GC–MS is the most universally applicable of the techniques and was the standard for this study, but it is more complex and costly. GC–electron capture and GC–electrolytic conductivity are comparatively simple and low in cost. The former suffers from interference by water, however, and the

Table 1
MAXIMUM CONCENTRATIONS IN THREE POWER PLANT COOLING SYSTEMS

Species	Concentration in Recirculation Water (ng/g)	Atmospheric Concentration ($\mu g/m^3$)
Residual chlorine	4000	Not measured
Volatile trihalomethanes	15	35
Less-volatile haloorganics	<1*	<7*
Total organic carbon	5000–50,000	Not measured

* Concentrations may be higher in power plants that use secondary wastewater effluent.

latter has poorer sensitivity for haloorganics. Elimination of the water interference makes the simpler, low-cost GC–electron capture applicable.

Because chlorination at the host power plants was not continuous, there was no steady-state concentration of chlorinated species in the cooling systems. Nevertheless, it is useful to report maximum instantaneous concentrations as representative of the worst possible case. Table 1 shows the maximum concentrations obtained in nine tests at three power plants, using normal chlorination procedures.

On the other hand, listing maximum instantaneous concentrations can be misleading because most of the chlorinated species do not persist after the chlorination. Figure 1 gives the changes in the concentration of chloroform and residual chlorine during and after chlorination of a power plant recirculating cooling system. Note that maximum concentrations do not persist for more than one hour. Therefore other, more-realistic parameters of exposure to emissions from cooling towers should be modeled (calculated) to yield estimates of touchdown concentrations.

This study showed that chlorination beyond the breakpoint (the point where the residual chlorine concentration has decreased to a minimum) favors destruction of chloramines and formation of haloorganics, such as chloroform. Chlorination less than breakpoint favors just the opposite. Carbon tetrachloride (CCl_4) found at a few nanograms per gram in the recirculation water is most likely an impurity in the chlorine supply and not a product of the chlorination.

Residual chlorine in the atmospheric emissions was not measured. Because of chlorine's high solubility in water, however, the concentration in the drift is expected to be similar to that in the recirculation water. Other studies suggest that the atmospheric residual chlorine does not persist as the drift evaporates.

Trihalomethanes were the only volatile haloorganics detected. Bromoform ($CHBr_3$), bromodichloromethane ($CHBrCl_2$), chlorodibromomethane ($CHBr_2Cl$), and chloroform were detected, the last being most often the predominant species. Although the less-volatile fraction had a low concentration of measurable haloorganics, in some cases other organics were prevalent, especially if a plant used wastewater effluent for cooling system makeup feed (see total organic carbon in Table 1).

Using meteorologic factors (such as dispersion, ambient wind speed, and atmospheric stability class) and atmospheric exit flux from the tower, chloroform and total trihalomethane concentrations at plume touchdown were estimated to be 0.003 to 0.05 $\mu g/m^3$ and 0.05 to 0.8 $\mu g/m^3$, respectively.

This concentration of chloroform is less than the typical atmospheric background concentration in the United States, which is 0.2 $\mu g/m^3$. And because chlorination occurs only from one to three times every 24 hours for 20 to 120 minutes each time, the average estimated concentrations over a 24-hour period would be considerably less than these peak estimates, which are based on maximum concentrations in the emissions.

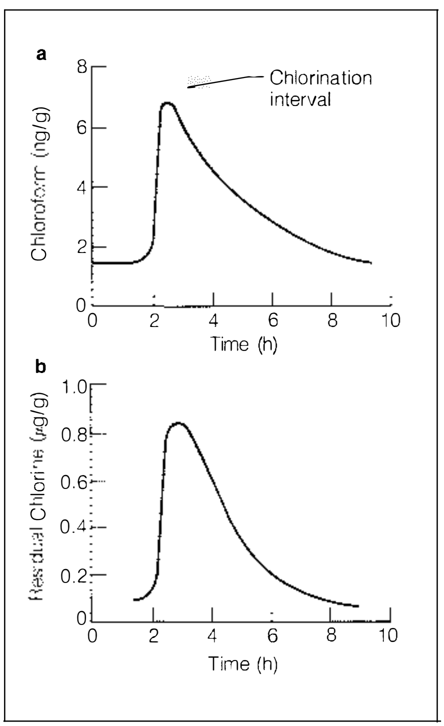


Figure 1 Concentrations of chloroform (upper) and residual chlorine (lower) in the cooling water of a power plant during and after chlorination. Other volatile haloorganics show similar behavior.

Because the emphasis of this study was on atmospheric discharge, dispersion for aqueous discharge was not modeled.

Evaluation and application

The project has developed a method for sampling and analyzing airborne volatile organic emissions from cooling towers, but because of the limited number of tests in this study, the method should be further evaluated before being recommended for general application. Analytic methods for measuring total residual chlorine and chlorine compounds in power plant cooling waters have been surveyed (EPRI EA-929), and instrumentation has been developed by the University of Wisconsin at Milwaukee for measuring specific chlorine compounds in cooling water (RP1435). These laboratory techniques have yet to be field-tested.

To assess the potential for ecologic effects resulting from exposure to cooling tower recirculation water, it is useful to compare the measured concentrations with the concentration that would kill 50% of the aquatic organism population as a result of 96 hours of exposure (LC_{50}). For trihalomethanes, LC_{50} is 7,000 to 97,000 ng/g, whereas the maximum recirculation water concentration measured was only 15 ng/g (Table 1). For less-volatile haloorganics, the maximum recirculation water concentration was even lower (<1 ng/g), except perhaps for power plants that use secondary wastewater effluent for cooling. For residual chlorine, LC_{50} is 30 to 1000 ng/g, and the maximum concentration in recirculation water was 4000 ng/g. Whether there is any reason for concern in this last case depends on the decay rate prior to blowdown, the type of organism exposed, the duration of exposure, and the degree of dilution. Information on dispersion into receiving waters and on speciation and persistence of residual chlorine compounds in relation to frequency of chlorination is still needed. Research into such topics would also yield a useful understanding of biofouling control efficiency. Methods to aid such research are being developed.

To assess the effect on health from human exposure to atmospheric emissions from cooling towers, it is useful to compare the study results with the threshold limit value (TLV), an occupational exposure-to-air recommendation for healthy adults based on 8 hours a day, 40 hours a week of exposure. For volatile trihalomethanes, the TLV is 5000 to 50,000 $\mu g/m^3$; the maximum atmospheric concentration measured was only 35 $\mu g/m^3$ (Table 1) and the estimated maximum concentration at plume touchdown was only 0.8 $\mu g/m^3$. Because the haloorganic concentrations are so much lower than the TLV, no health effects are expected from atmospheric emissions of residual chlorine. However, data are not available for such emissions, and additional research may be needed to resolve this uncertainty. *Project Manager: Jacques Guertin*

OCCUPATIONAL TOXICOLOGY OF CHEMICALS IN THE UTILITY WORKPLACE

Until recently, concern about long-term health effects of occupational exposure to chemicals was the exclusive province of occupational health and safety personnel in the chemical industry. Growing worker awareness and concern, court decisions, and government regulation, especially the OSHA Hazard Communication Standard, have broadened markedly the spectrum of industries concerned with occupational chemical exposures.

For the electric utility industry, several challenges must be met to achieve the goals of controlling exposure to hazardous chemicals and to comply with the right-to-know laws and regulations. The first challenge is to identify the wide variety of generic and trade name chemicals routinely used in operations and maintenance. Trade name products present a special problem—formulation data may be withheld by manufacturers for competitive reasons.

A second challenge for utilities may be the logistics of complying with right-to-know provisions of state laws and the OSHA Hazard Communication Standard. Toxicity data supplied by manufacturers are often out of date or incomplete, and to obtain the necessary information for all the chemicals routinely used in a utility of even moderate size is a formidable task that requires a substantial commitment of time and staff. Once collected, the data must be effectively communicated to plant supervisors, health and safety personnel, and employees who have an exposure potential.

The purpose of the EPRI study is to evaluate the potential for long-term health effects from exposure to chemicals used in the electric utility industry and to develop a computerized data base of their toxicologic properties to assist utilities in complying with OSHA regulations. The study was conducted in two phases. Phase 1 identified the chemicals to which utility workers could be exposed, determined the possible levels and frequency of exposure, and conducted an initial screening for potential long-term health effects associated with exposure to these chemicals. Phase 2 collected detailed toxicity information for chemicals of interest. This information formed the basis for the development of a computerized system that linked toxicity information on generic chemicals with information on formulations of trade name chemicals. In addition, it ranked chemicals according to their potential for long-term effects and developed detailed monographs on the toxicity of the chemicals ranked highest in concern.

A survey of approximately 100 utilities identified over 700 generic chemicals to which workers might be exposed. Researchers then screened the list by evaluating toxicity information, focusing on potential carcinogenicity, mutagenicity, reproductive toxicity, and neurotoxicity. This screening exclued about 120 nontoxic chemicals from further study.

There remained more compounds than could be carefully analyzed by this project. Therefore, a panel of toxicologists assigned numerical scores to the remaining chemicals according to their potential to cause long-term effects. If toxicity information for a chemical was limited or lacking, the panel attempted to estimate its toxicity on the basis of information on structurally related chemicals. A panel of industrial hygienists assigned numerical scores for the same chemicals according to the exposure potentials of various job classifications in utility operations. The scoring values assigned by the two groups to each chemical were then collated and tabulated. Thus, separate listings of the chemicals in the order of concern were compiled for carcinogenicity, mutagenicity, and reproductive or teratologic effects. These lists were then consolidated.

Additional toxicity information was collected on all chemicals by using 11 computerized data bases and more than 25 other document sources. Chemical hazard monographs were prepared on the 25 chemicals ranked highest:

Aromatic petroleum distillates
Barium
Benzotriazole
Bis(tri-n-butyltine)oxide
Bromotrifluoromethane
Carbonylsulfide
Chlorobenzene
Cobalt naphthenate
Creosote
Cresylic acid
Dimethylarsinic acid (cacodylic acid)
Dioxane
Formaldehyde
Glycol ethers (2-ethoxyethanol, 2-methoxyethanol)
Hydrazine
2-methyl-4-chlorophenoxy acetic acid (MCPA)
Methylisobutylketone
Methyl-n-butylketone (2-hexanone)
Pentachlorophenol
Potassium dichromate
Sodium dichromate
Tetrachloroethylene
Tetraethyl lead
Trichloroethane
Trichloroethylene

These monographs present current information on physical and chemical properties, exposure standards, recommended work practices, controls, emergency procedures, protective measures, and medical surveillance procedures, in addition to detailed toxicity information for both humans and animals.

To ensure completeness of the master list of chemicals and chemical products, the study team conducted a second survey of chemicals and chemical products used by utilities. Names of chemicals, chemical product lists, or Material Safety Data Sheets were solicited from all utilities listed on the EPRIMAIL roster and from those listed as members of the Edison Electric Institute's Committee on Safety and Industrial Health. In total, about 2500 different chemical product names were identified by trade name and manufacturer, and they were added to the existing inventory.

The Chemtrace chemical toxicity data base, permits the user to identify all trade name chemicals that contain any generic chemical in the data base. Conversely, the system can identify the constituents of a trade name product and generate a product hazard profile in the Chemtrace format for each constituent.

The data base is designed for use on an IBM personal computer or IBM-compatible computer, using Ashton-Tate's dBase III software. It consists of an extensive index to the hard-copy product hazard profiles and allows for the production of a variety of summary reports sorted by product, manufacturer, constituents, type of chronic health effect, and regulatory information. A menu-driven interactive program allows the user to add and update information, produce custom reports, and obtain information on individual products, as needed.

Product hazard profiles that use the Chemtrace format meet the requirements for compliance with federal (OSHA) and state right-to-know laws. Nine hundred profiles have been prepared. An additional 1500 product names have been identified for hazard profile development. The information for most of these products is being provided by the manufacturers and verified and/or supplemented from the information sources mentioned earlier. Over 150 manufacturers have been contacted, and more than half have responded or are in the process of responding to requests for additional information.

The project will be completed mid 1986; the report, including the disk, will be available at that time from the Research Reports Center. *Project Manager: Walter Weyzen*

R&D Status Report
ENERGY MANAGEMENT AND UTILIZATION DIVISION

Fritz Kalhammer, Vice President

TESTING AND EVALUATING LEAD–ACID PEAKING BATTERIES

EPRI studies revealed a need to demonstrate that lead-acid batteries can be economically attractive for utility energy storage and load management (EM-2769, EM-3535, and EM-3872). To confirm this, EPRI obtained a 500-kW, 500-kWh battery and a 500-kW ac/dc converter and control system for evaluation at the Battery Energy Storage Test (BEST) Facility in Hillsborough, New Jersey, which is operated by Public Service Electric & Gas Co. (PSE&G) for DOE and EPRI. Baseline cycling of the battery began in 1984; tests for customer-side and utility applications began in May 1985 and were more than 80% complete by the end of January 1986. The battery operates reliably with minimal maintenance and discharges about 70% of the energy supplied to it at the one-hour high rate. However, converter and control problems have clearly shown the need for developing complete performance specifications before procurement and for finding supplier teams that cooperatively can manufacture and install a reliably integrated system. Once testing is concluded early in 1986, the system will be put to use in a load management application at a site to be selected.

Utilities that wish to defer generating capacity or enhance operating flexibility (and reduce premium fuel use at the same time) should consider lead-acid battery storage systems. Recent studies by PSE&G, sponsored by DOE, and by Bechtel Group, Inc., for DOE and EPRI, showed that batteries can have a breakeven capital cost exceeding $1000/kW (five-hour discharge). Lead-acid battery systems should achieve this goal.

Because battery systems are modular, virtually environmentally benign, and potentially highly reliable, they can be attractive for either utility or customer-side load management applications. However, specific customer economics based on rate structures often do not reflect actual economic benefits/liabilities for the utility system. Therefore utilities should evaluate economic benefits of load management batteries from a system standpoint and then provide savings to the customer that are consistent with these benefits.

Batteries offer a number of unique advantages over other load management alternatives. First, the customer does not have to change its use of electricity to gain economic benefits. Second, batteries can be dispatched by utilities without action by the customer. Third, because batteries can be operated with most types of electrically powered equipment, the amount of energy managed can be highly flexible throughout the year.

Three events in 1985 greatly enhance the prospects for lead-acid batteries in utility and customer load management applications. Through innovative design for standardized engineering and construction, Bechtel has lowered cost estimates for lead-acid battery systems by 30% to $540–$1150/kW for 2-MW systems with energy capacities ranging from 1 to 8.6 MWh, respectively (EM-4200). Under a DOE contract, Exide built full-scale 5-kWh lead-acid cells that Argonne National Laboratory tested for over 2000 cycles at 50°C, equivalent to over 4000 cycles for 15 years at ambient temperature, or nearly a 50% increase over the previously expected cycle life. Finally, a 500-kW, one-hour lead-acid battery system has been built and is being successfully tested at the BEST Facility, as described below.

Testing

The deep discharge battery produced by GNB, Inc., is warranted for 2000 cycles or eight years. It is configured as three strings of 18 six-cell modules that can be connected for parallel (250-V) or series (750-V) operation (Figures 1 and 2). The battery incorporates air-driven electrolyte agitation and uses a relatively gentle, five-hour charging regime (finishing at 2.33 V per cell) to extend life and improve efficiency. Its long, narrow modules provide a high surface-to-volume ratio for good heat rejection, and its interconnecting cables are integrally welded with the cell lugs at the positive end of the modules for easier installation and more-reliable electrical connection.

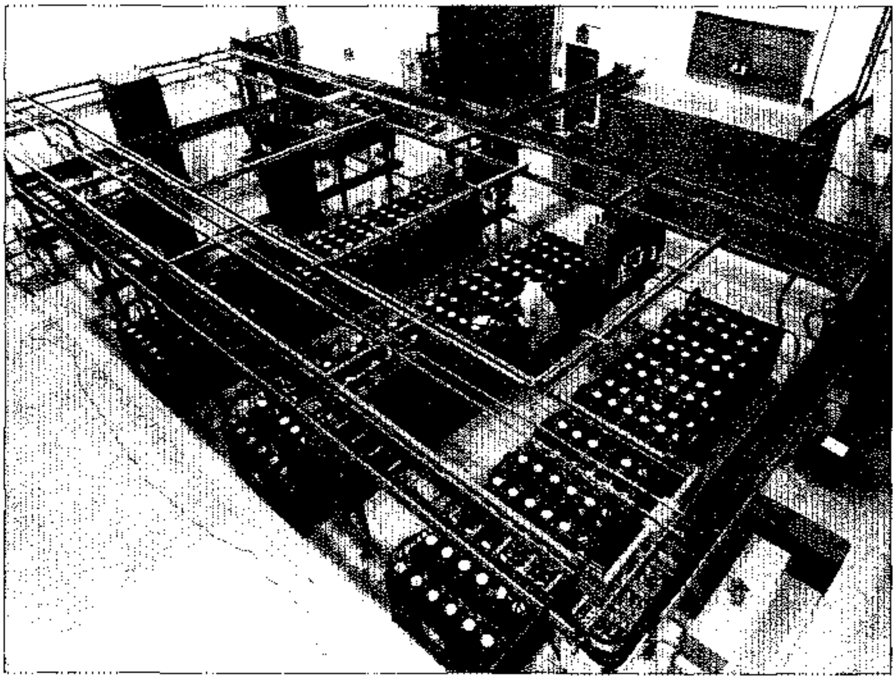
Operating frequency is specified at 1–5 days a week, 50–250 days a year. Energy efficiency (dc/dc) is to be 70% minimum, as measured over any 50 consecutive cycles including equalization. Maintenance includes physical inspection, recording cell voltages and specific gravities, cleaning, and watering, with a maintenance interval not less than every three months.

Using BEST Facility equipment as the balance of plant, the initial battery baseline test program included 36 cycles with continuous discharges between 1 and 10 hours, recharging in less than 5 hours. Weekly dc/dc energy storage efficiencies (the ratio of dc discharging to charging energy) averaged 72% at the 1-hour rate of discharge and 79% at the 5–10-hour rates.

No operating or maintenance difficulties occurred with the battery during these baseline tests. Although battery life cannot be determined from these short tests, factory data have been collected to be correlated eventually with the life of each of the 324 individual cells. The correlations may yield a method to predict battery life from initial construction and qualification test data.

The converter, developed by Firing Circuits, Inc., can be arranged for either 250-V operation (parallel battery strings) with a 440-kW ac rating, or 750-V operation (series battery strings) with a 500-kW ac rating. The 12-pulse power module (two 3-phase, 6-pulse bridges) includes an ac overcurrent circuit breaker, an ac harmonic filter, ac line inductors to limit switching transients, dc line inductors to limit

Figure 1 This 500-kW, 500-kWh lead-acid battery system for use in load management has been undergoing testing at the BEST Facility. The battery, purchased by EPRI, features three strings of 108 cells each.



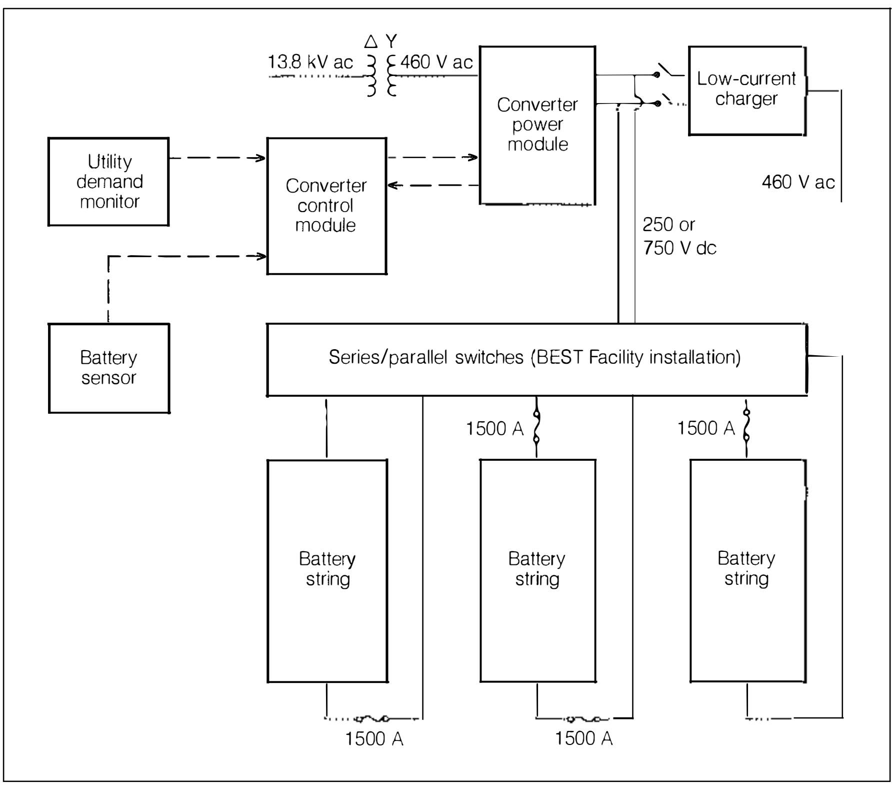


Figure 2 Schematic of the battery energy storage system. A microprocessor in the control module directs the discharging and recharging of the battery as demand fluctuates. This system was tested for both utility and customer applications.

commutation fault current rate-of-rise, dc fusing to clear commutation faults, bridge current equalization circuits, dc contactors for charge/discharge selection and load isolation, front panel dc current selection, digital dc current and dc voltage meters, and a button for manual-control shutdown. Drawing all power from a 460-V feed (±10%), a delta-to-delta and ungrounded-wye transformer isolates the two thyristor bridges and battery from ground. Four fuses at the battery string ends (Figure 2) protect the parallel configured battery (250 V) from effects of high circulating currents between strings in the unlikely event of a double-ground fault.

A stand-alone microprocessor control module responds to battery conditions and to a power demand signal to limit utility demand at a customer feeder. The converter discharges up to 500 kW into the feeder to maintain a customer-selected demand limit. For example, if the demand limit is 4 MW, a load of 4.2 MW will cause the converter to discharge 200 kW from the battery into the load, reducing utility demand to 4 MW. The control system can be set to charge the battery whenever the load demand is well below the demand limit. A charge-suppression contact can be provided to suppress daytime charging, if desired. Control system operation conforms to GNB's prescribed charging regime and maintains GNB's discharge, temperature, and voltage limits. Manual switchover to a low-current charger for continued float charging will be automated before the test program is completed.

Applications testing started in May 1985 to operate the converter and battery in simulated end-use installations. A total of 94 cycles in the planned test program and 81 additional runs were completed through the end of 1985. Utility applications included peak shaving, economic dispatch, and spinning reserve discharges at rates in the range of 1–10 hours. Load management applications included operations typical of commuter railroads and heavy industry. The BEST Facility derives a utility power demand signal for customer-side applications by subtracting converter power output from a computer-synthesized load signal based on utility customer data (EM-2995).

The energy storage system delivers 580 kWh ac in a 500-kW sustained discharge, and at least 600 kWh ac in lesser discharges (≤300 kW) during daily operation in ambient air temperatures of 20–25°C. More energy can be discharged if load shape, economics, and vendor's warranty allow daytime partial recharge. Daily output up to 980 kWh has been demonstrated.

The customer railroad application discharges the battery to shave morning and eve-

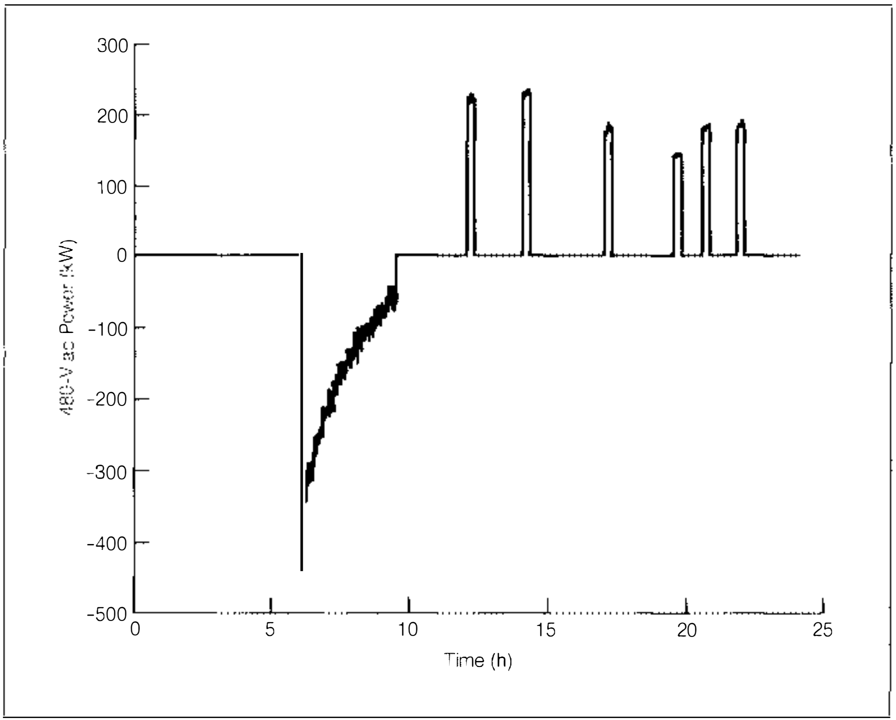


Figure 3 Results of a load-leveling test using simulated demand from a steel mill. The negative peak at the left is the charging half cycle; the peaks at the right are discharges in response to short-term high demand. The total discharge was 425 kWh.

ning demand peaks. The industrial application shaves demand spikes (Figure 3), discharging a total of about 2 hours per 10-hour cycle. Because the load varies from day to day, low-load days reduce the average energy discharged well below battery capacity. In a utility economic discharge test, power was proportional to PSE&G's running rate, plus a 20-hour rate constant output whenever the running rate exceeded a threshold value. A utility 500-kW peaking test discharged the battery at 500 kW to the capacity of the battery.

At an ambient air temperature of 25°C, the battery temperature remained below the manufacturer's limit of 43°C, reaching a high of 40°C at the end of the utility 500-kW discharges. The converter is programmed to halt discharge when the battery heats above 40°C, which did occur once.

Maintenance requirements

The battery has been continuously operable except for two days of scheduled maintenance each quarter. Preventive maintenance included inspection and recording pilot-cell temperatures and voltages weekly, electrolyte levels monthly, and voltages, gravities, temperatures, levels, and intermodule resistance of all cells quarterly. GNB performs the quarterly maintenance, using two persons during two days. Quarterly watering has proved adequate, and only minor mechanical problems have occurred.

The electrolyte agitation air supply has worked reasonably well since introducing a water condensate filter and drain on the string manifolds. No difference has been observed between the performance of the 51 agitated modules and the 3 modules left without agitation as an experiment. An experiment to cease agitation of an entire string and to assess the requirements for equalization is under way during the final months of the test program. If the electrolyte is not agitated, the cells may need periodic special equalization.

The converter has been in use for daily cycling in the 750-V mode since May 1985. However, acceptance was delayed for two months while filter and line-inductor chokes were corrected to eliminate overheating in sustained 500-kW operation. The converter has not been able to operate outside of its narrow specifications range (sustained discharge of 1000 A at 253 V in parallel or 600 A at 762 V in series when supplied with ac voltage as high as 475 V). Converter and control subsystem design requirements for dual-mode operation were not adequately specified at the outset; consequently, the subsystem's performance had to be incrementally improved as limitations were identified. Continuing software and component development caused delays and modifications in the test program.

Future customer-side plans

EPRI has offered to sell this battery energy storage system to a utility or to a team of a utility and one of its customers at a price substantially below market value. The conditions of sale are that the purchaser must use the battery for load management, provide progress reports to EPRI for two years of commercial operation, and allow EPRI reasonable access to the battery. The testing at the BEST Facility is scheduled to be complete by May 1986, and the system will be ready for removal.

The BEST Facility testing program is demonstrating that the lead-acid battery has the performance characteristics necessary for load management applications. However, this test program has shown that inadequate understanding of operating requirements for the battery and the power conditioning and control equipment can delay initial plant startup and may also decrease plant availability. These problems can be mitigated by integrated system design and better specifications for procurement, installation, and acceptance testing. *Project Manager: William Spindler*

R&D Status Report
NUCLEAR POWER DIVISION

John J. Taylor, Vice President

PIPING INTEGRITY RESEARCH

The design equations of the American Society of Mechanical Engineers (ASME) Nuclear Piping Code were based on the idea that static plastic collapse is a well defined failure mode that identifies the capability of a piping system under combined dynamic and static loading. Numerous studies have shown that fatigue ratchetting is a more likely failure mode for pressurized piping that is dynamically overloaded. (Ratchetting is an incremental, progressive plastic deformation that occurs with each cycle of dynamic loading.) Use of this more-realistic failure mode could mean that the dynamic stress capacity of nuclear piping can be substantially increased if it can be shown that fatigue ratchetting is the dominant failure mechanism. Documenting the actual failure mode for dynamically overloaded piping is the objective of EPRI's three-year research project, which began in early 1985 and is being conducted by General Electric Co. (RP1543-15). The experiments on materials and components of pipes and on pipe systems focuses on assembling the data and engineering analysis necessary to improve the design equations that underlie the ASME code.

Piping is an integral part of a nuclear power plant, and great attention has been given to piping in connection with plant safety and reliability. Current interest focuses also on how to make nuclear piping designs more cost-effective and tolerant of the complex design process of a nuclear plant. The data and the engineering theory from EPRI's research are expected to support improvements in the standards and regulations governing nuclear piping.

At this time, nuclear piping is designed to be much stiffer than most nonnuclear piping, which is a result of the combined requirements of the ASME code and NRC regulations concerning the treatment of dynamic loading. The most effective way designers have found to deal with these requirements has been to add snubbers to the pipe system, which accommodates thermal expansion motion but provides stiff constraint to dynamic loading.

As a result of this solution, modern nuclear plants have been coming on-line with about 2000 snubbers, which are proving to be less reliable in service than was anticipated. Snubbers can fail through lockup (which prevents thermal expansion), through excessive drag force, or through failure to activate. The failure rate has been high enough that NRC regulations require testing every 18 months. If more than seven failures are found, the testing interval can become as short as 1 month.

Although this high number of failures has not occurred, nuclear utilities are concerned that snubber problems can cause unscheduled outage, higher radiation exposure of employees, and major maintenance costs. (The estimate for snubber maintenance is about $1 million a year for a modern nuclear plant.) With these incentives, there is considerable motivation to find ways of reducing the required number of snubbers. One way is to reevaluate the current ASME code to remove unwarranted conservatisms.

In developing the design equations for the current ASME code, simplifications were made, one of which was that dynamically caused stresses would be treated the same as if they were caused by static loads. Plastic collapse was the assumed failure mode for dealing with combined static and dynamic loading. This is a conservative assumption because under dynamic loading, several nonlinear phenomena occur as a piping system is loaded dynamically toward failure: (1) the apparent damping increases, (2) the stiffness of the piping decreases, causing a detuning effect, and (3) even after one cross section of the pipe system becomes plastic, the excessive dynamic load is redistributed to another cross section due to redundancy. A recent analysis concluded that for most dynamically overloaded pipes, the failure mode is expected to be fatigue or fatigue ratchetting leading to cracking (EPRI NP-4210). If that conclusion can be verified, then significant modifications can be incorporated into the ASME code that would lead to the design of piping systems with lower natural frequencies and fewer dynamic snubbers.

EPRI began this research to address uncertainty about the failure mode of dynamically overloaded pipe systems that are also pressurized, and it will conduct three types of experimental tests: materials, pipe components, and small-pipe systems. General Electric is the prime contractor and Anco Engineers is the subcontractor for component tests. (A subcontractor for the system testing has not been chosen.) The objectives of the research are to develop an improved, realistic, and defensible set of piping design rules for inclusion in the ASME code and to develop an engineering theory to generalize the failure behavior.

The project will test approximately 106 material specimens, 40 pipe components, and 3 small piping systems. The expected cost of the three-year project is $2.9 million, of which $700,000 will be provided by NRC.

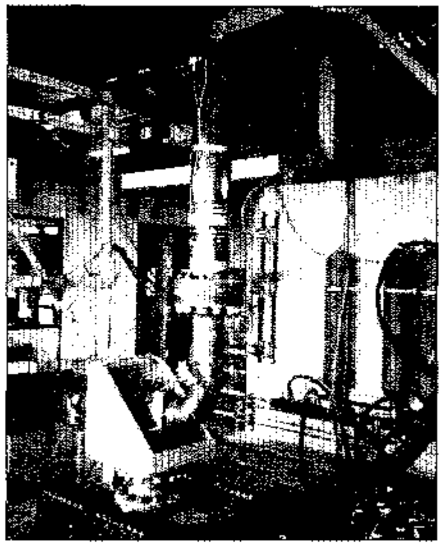
Pipe component tests

Forty failure tests are planned on components (e.g., elbows, tees, reducers, nozzle connections, and support fittings with struts and lugs). The selected test specimens are 6-in nominal pipes (schedules 10, 40, and 80) of both carbon steel and stainless steel. The components will be hydraulically pressurized at room temperature to various levels; the input dynamic overload will cover a range of frequency contents representing seismic (low-frequency), hydrodynamic (mid-frequency), and water hammer (high-frequency) events. Using high-power actuators, a shake table will produce the desired base motions of seismic and hydrodynamic events. Rupture disks or explosive-type air guns will be used in the water hammer events.

During the shake tests, the specimen will be attached to a specially designed shake-sled fixture at one end and to an extended weight arm at the other (Figure 1). The sled will be driven by four 11,000-lb (4990-kg) hydraulic actuators that can subject the sled to 20-g accelerations. The weight arm will react to this base motion and induce severe cyclic inertia loads to the component. A 20-second amplified record from a prototype earthquake has been selected as the low-frequency input driving force.

The first component test of a carbon steel elbow was completed in September 1985. Preliminary results suggest that the steel elbow can absorb significantly more dynamic energy than anticipated. Collapse did not occur for all the tested speciments. In the schedule 10 and 40 elbow tests, the fatigue ratchetting type of failure mode (swelling and throughwall cracking) developed after two or three applications of a 20-second dynamic loading at a stress level equivalent to 18–24 times the stress level of a safe shutdown earthquake (SSE). The required ASME code margin of safety for the SSE allowable stress is approximately 1.4 (this suggests at least an order of magnitude excess margin exists in the current standards). During the testing, the peak dynamic moment reached almost twice the static collapse moment, and the apparent damping of the system was computed as high as 34%.

Figure 1 This apparatus tests a pipe component under combined static and dynamic loads. One end of an elbow of 6-in pipe is fastened to the beveled box on a shake sled, the other to a heavy inertial arm with a large weight on its end. It took 18–24 times the allowable stress of a safe shutdown earthquake to produce leakage failure.



Pipe system tests

Current piping design is based on components; however, an actual piping system is more complex and is statically indeterminate. It can undergo significant stress/strain redistribution before large deformation can occur to induce a system failure. In an actual piping system, the dynamic capability against failure will be influenced by the system redundancy. The objective of the planned tests, therefore, is to demonstrate the realistic failure of the system under the combined effects of pressure, gravity, and severe dynamic load.

Three piping systems will be tested to failure under simulated earthquake, hydrodynamic, and water hammer loads. Each system test will measure the accumulated load cycles and piping system response up to the point of the first component failure (coolant leakage); after failure, the failed component will be replaced and the system retested under the same loading condition.

The seismic and hydrodynamic tests will need three to five high-powered, hydraulic-actuator-driven shake sleds to initiate the support motion. Currently, the Energy Technology Engineering Center of Rockwell International Corp., under DOE and NRC sponsorship, is preparing a similar piping system test at its newly established fragility test facility. Because very high testing capacity is necessary, the contractor and final work scope will not be specified until results from Anco's component tests and Rockwell's system test have been evaluated.

Pipe material tests

The pipe material tests focus on understanding quantitatively how cracks form and propagate in pipe metals, leading to coolant leakage. Understanding this phenomenon requires considering the combination of mean stress and alternating stress under which ratchetting occurs. There is no complete engineering theory to show quantitatively just when ratchetting will occur in real pipe materials and how extensive it will be. Once the amount of ratchetting has been determined, it is necessary to determine how this ratchetting influences the fatigue life.

Four piping materials have been selected for testing to ensure that the variety of behaviors possible in nuclear piping are evaluated: A333 grade 6 (carbon steel); type 316NG (stainless steel); A387 grade 22, class 2 (2¼Cr-1Mo steel); and A533 grade 6 (Mn-½Mo-½Ni alloy steel). Data on baseline fatigue and cyclic stress-strain properties will be obtained.

The basic ratchet testing will consist of so-called two-bar simulation tests, in which a bar is placed in a computer-controlled cyclic test machine. The bar will be strain-controlled and the effect of a second bar (at a different state of residual stress) in parallel with the load path of the first bar will be simulated with the computer control. In this way, a very simple materials experiment can be conducted to evaluate the ratchetting. Experiments on pressurized pipes and on rectangular beams loaded with combined tension and bending will be conducted to verify that two-bar simulation indeed represents the more complex behavior in a pipe.

If this program adequately demonstrates the large real dynamic margin present in current nuclear designs, this margin could be reduced to permit more-balanced piping designs; that is, fewer snubbers will be required and pipe systems will have lower frequencies with more flexibility to accommodate the stresses associated with normal operation. *Project Managers: S. W. Tagart, Jr., and Y. K. Tang*

PWR PRIMARY WATER CHEMISTRY GUIDELINES

Water quality is important to a broad range of requirements for power plant design, operation, and materials performance. Guidelines that define target specifications for reactor water quality and describe ways to bring water quality up to those specifications greatly assist implementation of the findings of water chemistry research. Guidelines for the pressurized water reactor (PWR) secondary system and boiling water reactor (BWR) water chemistry have already proved valuable in aiding utilities to improve water quality. Now an industry committee of utility and vendor representatives, initiated by EPRI, has prepared guidelines for PWR primary system chemistry.

The Steam Generator Owners Group prepared water chemistry guidelines for PWR secondary systems in 1983, and the BWR Owners Group for Intergranular Stress Corrosion Cracking Research did the same for BWRs in 1984. The significant improvements in water quality in these systems have been attributed (at least in part) to those guidelines, which have been adopted by a large majority of U.S. nuclear power plant owners.

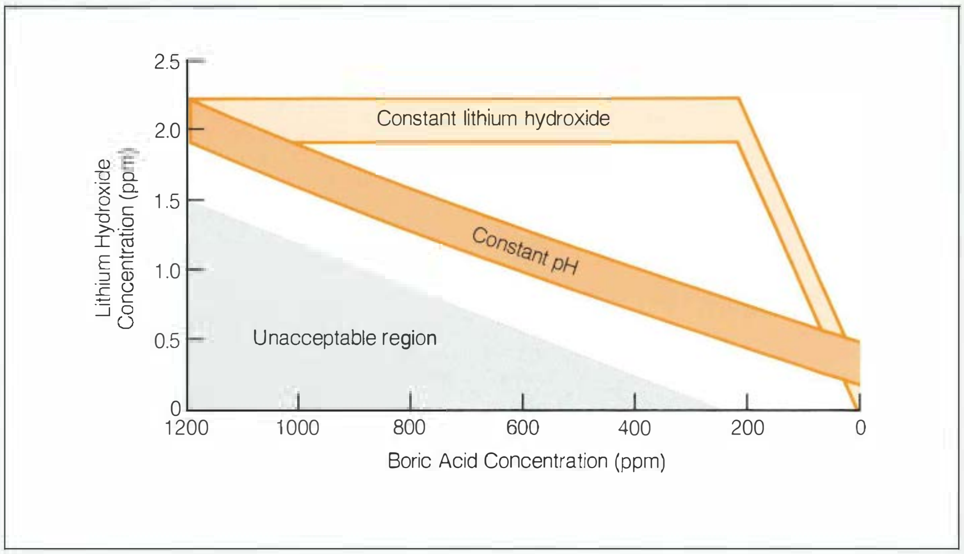
To complete the coverage of nuclear plant cooling systems, EPRI's Nuclear Power Division established an industry committee in April 1985 with the goal of preparing PWR primary water chemistry guidelines by March 1986. As with the earlier guideline groups, the committee was composed of representatives of member utilities and nuclear steam supply system vendors. However, whereas the other guidelines were sponsored by owners groups, these guidelines were sponsored by the Engineering and Operations Department, there being no owners group for PWR primary systems.

The purpose of the PWR primary chemistry guidelines is to maximize the long-term integrity and availability of PWR plants by providing technical recommendations for (1) controlling radiation exposure through chemistry, (2) maximizing component and materials integrity, and (3) maximizing fuel cladding integrity. Of these technical objectives, the first is concerned with the complex issue of pH control (which is one of the more important aspects of the guidelines), and the second and third define impurity levels.

In reactor coolant systems and fuel materials, general corrosion and stress corrosion cracking processes are controlled by minimizing dissolved oxygen, chloride, fluoride, and sulfur, and by maintaining a basic pH. During operation the oxygen concentration is controlled by maintaining an overpressure of hydrogen; this also helps minimize the buildup of corrosion products on fuel cladding. Silica, aluminum, calcium, and magnesium, as well as suspended solids, should also be controlled to reduce cladding corrosion resulting from dense deposits forming on the fuel.

Recent research and limited plant data suggest that pHs higher than now used may be beneficial. However, potential fuel and materials concerns with lithium hydroxide concentrations above 3 ppm require study before higher concentrations can be recommended for general use. Most U.S. PWR operators have adopted a constant-pH operational scheme, as depicted in Figure 2. A few utilities have adopted a constant lithium hydroxide regime, also shown in the figure, which gives a steadily increasing pH through the cycle. Theoretical predictions suggest that this is about as effective as constant pH in controlling radiation buildup, although it is recognized that there is greater potential for activity transport with this approach.

Figure 2 Boric acid is added to PWR primary system water for reactivity control and lithium hydroxide for pH control. The boric acid concentration decreases during a fuel cycle. By coordinating the lithium hydroxide concentration with that of the boric acid to maintain a constant pH (lower band), fuel deposit formation and transport can be reduced. An acceptable alternative is to maintain a constant lithium hydroxide concentration through most of the cycle (upper band), although this has a greater potential for activity transport. Lower pH values (lower left section of graph) result in heavy deposits on the fuel.



Three main points formed the rationale for establishing control parameters.

- Impurity inventory in the reactor coolant system should be kept to a practical and achievable minimum.

- Action levels (levels triggering corrective response) should be based on quantitative information relating water chemistry variables to the corrosion behavior of materials, fuel cladding corrosion, and radiation buildup, and they should be consistent with plant technical specifications. In the absence of quantitative data, prudent and achievable action levels should be recommended.

- Control values and diagnostic values should be recommended. Control value limits require strict supervision, and diagnostic values identify parameters that may be important but for which no quantitative data are available to support remedial action requirements. Diagnostic values are also assigned to parameters that can assist chemistry staff in the interpretation of deviations in control parameters. Both values should be reliably measurable with currently available equipment.

On the basis of the principle that plants should be operated with the lowest practical impurity concentrations consistent with the circumstances, three action levels are defined for remedial action to be taken when parameters are confirmed to be outside the control values.

The first action level represents the range outside of which long-term system reliability may be affected. This level generally represents limits for normal plant operation, and efforts should be made to return to the appropriate range within seven days. The second action level represents conditions in which significant damage could be done to the system in the short term, thereby warranting a prompt correction. The third action level represents the limit beyond which engineering judgment indicates that it is inadvisable to continue to operate the plant.

Guideline values are defined for the plant status modes of cold shutdown, startup, and power operation. To conform to these recommendations, the necessary plant chemistry data must be obtained and reviewed in a timely manner.

The guidelines committee defined generic objectives for data evaluation. Prompt interpretation, in particular, can identify adverse trends long before they indicate the need for plant shutdown, so corrective action can be well planned.

Experience has shown that implementation of chemistry guidelines is hampered without the necessary degree of management support; therefore the guidelines include a chapter on management responsibilities. The guidelines provide a model from which utilities can generate their own specific chemistry control programs, an important step toward improving the economics of plant operation. *Project Managers: R. A. Shaw and C. J. Wood*

New Contracts

Project	Funding and Duration	Contractor and EPRI Project Manager
Advanced Power Systems		
Residual Oil User's Guidebook (RP2106-2)	$672,500 26 months	Southwest Research Institute; *H. Schreiber*
Utility Assessment of Indirect-Fired Gas Turbine Power Plant (RP2387-3)	$99,900 14 months	Hydra-Co Enterprises, Inc.; *A. Cohn*
Chemical Coal Transformation With the ChemCoal Process (RP2655-5)	$300,000 11 months	University of North Dakota Energy Research Center; *C. Kulik*
Use of High-Pressure Oxygen Plants in IGCC Systems (RP2699-1)	$199,000 12 months	Union Carbide Corp.; *W. Reveal*
Combustion of Low-Btu Gas in a Utility Boiler (RP2777-1)	$170,000 13 months	Illinois Power Co.; *H. Schreiber*
Coal Combustion Systems		
Cool Water Slag Utilization (RP985-9)	$43,000 5 months	Praxis Engineers, Inc.; *S. Alpert*
PCB Removal From Concrete and Asphalt (RP1263-25)	$139,600 11 months	Quadrex HPS, Inc.; *R. Komai*
Filters for High-Temperature, High-Pressure Gases (RP1336-7)	$517,900 27 months	Technical University of Aachen; *O. Tassicker, S. Drenker*
Rotor Dynamic Characteristics of Wear Ring Configurations for Feedwater Pumps (RP1884-22)	$197,800 20 months	Case Western Reserve University; *S. Pace*
Feed Pump Procurement Guideline: Phase 3 (RP1884-24)	$131,700 12 months	P. R. Stech Corp.; *S. Pace*
Measurement of Interferences in Free Chlorine Residuals (RP2300-7)	$74,100 14 months	University of North Carolina; *W. Chow*
Assessment of Microbiologically Induced Corrosion in Fossil Fuel Power Plants (RP2300-12)	$32,300 7 months	Rensselaer Polytechnic Institute; *W. Chow*
Calcium Injection Upstream of a Fabric Filter for Simultaneous SO_2 and Particulate Removal (RP2784-1)	$490,400 12 months	Radian Corp.; *M. McElroy, R. Rhudy*
Electrical Systems		
Pyrolysis and Combustion of Utility Materials (RP2028-17)	$78,000 18 months	General Electric Co.; *G. Addis*
Device for Detection of Arcing Faults in Small Power Transformers: Phase 1 (RP2617-1)	$406,600 22 months	Westinghouse Electric Corp.; *H. Ng*
Energy Analysis and Environment		
Gas Absorption in Water Droplets (RP2023-8)	$450,000 34 months	Aerodyne Research, Inc.; *A. Hansen*
RILWAS Sierra Application (RP2174-12)	$40,000 1 month	Southern California Edison Co.; *R. Goldstein*

Project	Funding and Duration	Contractor and EPRI Project Manager
Guidebook on Response Modeling (RP2372-2)	$104,500 14 months	Putnam, Hayes & Bartlett, Inc., *J. Platt*
Energy Management and Utilization		
Computer Modeling of Lighting-HVAC Interaction (RP2418-7)	$75,000 17 months	Center for Building Technology; *G. Purcell*
Customer Preference and Behavior (RP2671-1)	$3,011,400 56 months	Booz, Allen & Hamilton, Inc.; *C. Gellings*
Heat Storage Furnace Field Test Management (RP2731-2)	$233,100 10 months	Science Applications International Corp.; *V. Rabl*
Smart House Equipment Specification (RP2830-1)	$450,200 11 months	NAHB Research Foundation, Inc.; *V. Rabl*
Nuclear Power		
Microchemistry and Micromorphology of Corroded Intergranular Surfaces (RPS302-23)	$41,200 11 months	Calgon Corp.; *C. Shoemaker*
Oxide Film and Surface Metal Composition and Morphology of Alloys 600, 690 Exposed to Various Environments (RPS302-25)	$47,200 12 months	Rockwell International Corp.; *C. Shoemaker*
Field Studies Related to Intergranular Attack (RPS306-21)	$190,800 10 months	Westinghouse Electric Corp.; *S. Hobart*
Flow Control Valve Evaluation (RP1935-10)	$79,400 20 months	Westinghouse Electric Corp.; *H. Ocken*
Feasibility of Corrosion Cracking Monitor: Phase 2 (RP2006-14)	$384,900 13 months	General Electric Co.; *J. Gilman*
Feasibility of Remote Fiber Fluorometry Monitor for Acidity in Oil (RP2013-2)	$100,000 11 months	DOE; *J. Matte*
Standards for Evaluation of Ultrasonic Inspection of Reactor Pressure Vessels (RP2165-6)	$343,100 7 months	Westinghouse Electric Corp.; *M. Behravesh*
Ultrasonic Wave Scattering and Characterization: Centrifugally Cast Stainless Steel (RP2405-18)	$112,000 12 months	Drexel University; *M. Avioli*
BWR Liquid Radwaste Processing Optimization (RP2414-15)	$47,300 5 months	Vance & Associates; *P. Robinson*
Steam Generator Survey (RP2599-3)	$58,800 16 months	Atomic Energy of Canada Ltd.; *T. Oldberg*
RETRAN Analysis of a BWR ATWS Severe Accident (RP2600-10)	$29,000 3 months	Energy, Inc.; *B. Sehgal*
Advanced-LWR Program (RP2660-1)	$5,341,500 55 months	Combustion Engineering, Inc.; *D. Noble*
Fracture Toughness Test (RP2680-4)	$105,000 8 months	General Electric Co.; *D. Franklin*
Evaluation of Steam Generator Sludge NDE: Current Practices (RP2755-2)	$90,100 8 months	Dominion Engineering, Inc.; *C. Williams*

New Technical Reports

Requests for copies of reports should be directed to Research Reports Center, P.O. Box 50490, Palo Alto, California 94303; (415) 965-4081. There is no charge for reports requested by EPRI member utilities, U.S. universities, or government agencies. Others in the United States, Mexico, and Canada pay the listed price. Overseas price is double the listed price. Research Reports Center will send a catalog of EPRI reports on request. For information on how to order one-page summaries of reports, contact the EPRI Technical Information Division, P.O. Box 10412, Palo Alto, California 94303; (415) 855-2411.

ADVANCED POWER SYSTEMS

Proceedings: Conference on Coal Gasification Systems and Synthetic Fuels for Power Generation
AP-4257-SR Proceedings (TCO83-933); Vol. 1, $62.50; Vol. 2, $55.00
EPRI Project Manager: S. Alpert

Low-Rank Coal-Water Slurries for Gasification
AP-4262 Final Report (RP2470-1); $32.50
Contractor: University of North Dakota
EPRI Project Manager: G. Quentin

Verification Testing of the S-Cubed Entrained-Flow Coal Gasification Code
AP-4289 Topical Report (RP1037-3); $25.00
Contractor: Los Alamos National Laboratory
EPRI Project Manager: G. Quentin

Determination of Autoignition and Flame Speed Characteristics of Coal Gases Having Medium Heating Values
AP-4291 Final Report (RP2357-1); $25.00
Contractor: United Technologies Research Center
EPRI Project Manager: L. Angello

Fatigue-Life Assessment Methods and Application to the Model WTS-4 Wind Turbine
AP-4319 Final Report (RP1996-4); $32.50
Contractor: Hamilton Standard
EPRI Project Manager: F. Goodman

Rotationally Sampled Wind and MOD-2 Wind Turbine Response
AP-4335 Final Report (RP1996-12); $32.50
Contractor: Battelle, Pacific Northwest Laboratories
EPRI Project Manager: F. Goodman

Chemistry, Scale, and Performance of the Hawaii Geothermal Project-A Plant
AP-4342 Final Report (RP1195-12); $32.50
Contractor: Hawaii Electric Light Co., Inc.
EPRI Project Manager: M. McLearn

Corrosion in Quench Systems of Entrained Slagging Gasifiers: Laboratory Study
AP-4344 Final Report (RP2048-6); $25.00
Contractor: IIT Research Institute
EPRI Project Manager: W. Bakker

Non-Coal-Derived Heavy Solvents in Direct Coal Liquefaction
AP-4345 Interim Report (RP2383-1); $32.50
Contractor: University of Wyoming
EPRI Project Manager: C. Kulik

Proceedings: Utility–Wind Turbine Industry Interaction Workshop
AP-4348 Proceedings (RP1996-17); $25.00
Contractor: Science Applications International Corp.
EPRI Project Manager: F. Goodman

Catalytic Liquefaction of Coal Using Supercritical Water-Solvent Mixtures
AP-4359 Final Report (RP2383-4); $32.50
Contractor: University of Notre Dame
EPRI Project Manager: C. Kulik

Two-Stage Liquefaction Catalyst Evaluation
AP-4378 Final Report (RP2561-1); $25.00
Contractor: Hydrocarbon Research, Inc.
EPRI Project Managers: W. Rovesti, N. Stewart

COAL COMBUSTION SYSTEMS

Field Tests of Fabric Filters on Full-Scale Coal-Fired Utility Boilers
CS-3848 Final Report (RP1129-8); Vol. 1, $32.50
Contractor: Southern Research Institute
EPRI Project Manager: R. Carr

Treatment of Silica-Limited Cooling Water
CS-4212 Final Report (RP1261-8); Vol. 1, $47.50; Vol. 2, $62.50; Vol. 3, $40.00
Contractor: Stearns Catalytic Corp.
EPRI Project Manager: W. Micheletti

Seminar Proceedings: Prevention of Condenser Failures—State of the Art
CS-4329-SR Proceedings; $62.50
EPRI Project Managers: B. Syrett, R. Coit

Proceedings: 1985 Symposium on Stationary Combustion NO_x Control
CS-4360 Proceedings (RP2154-5); Vol. 1, $85.00; Vol. 2, $55.00
Contractor: Acurex Corp.
EPRI Project Manager: D. Eskinazi

Ceramic Filter Elements for High-Pressure, High-Temperature Gases
CS-4382 Topical Report (RP1336-6); $25.00
Contractor: Westinghouse Electric Corp.
EPRI Project Managers: O. Tassicker, S. Drenker

Froth Flotation for Fine-Coal Cleaning
CS-4383 Final Report (RP1852-4); $25.00
Contractor: WEMCO
EPRI Project Manager: R. Row

ELECTRICAL SYSTEMS

Optimization of Induction Motor Efficiency: Experimental Comparison of Three-Phase Standard Motors With Wanlass Motors
EL-4152 Final Report (RP1944-1); Vol. 3, $47.50
Contractor: University of Colorado
EPRI Project Manager: J White

Harmonics and Electrical Noise in Distribution Systems: Measurements and Analyses
EL/EM-4290 Final Report (RP2017-1); Vol. 1, $32.50
EPRI Project Manager: W. Shula
Contractor: SRI International

Fault Location Techniques for HVDC Lines
EL-4331 Final Report (RP2150-1); $32.50
Contractor: Washington State University
EPRI Project Manager: H. Mehta

Methodology for Predicting Torsional Fatigue Life of Turbine Generator Shafts Using Crack Initiation Plus Propagation
EL-4333 Final Report (RP1531-1); $32.50
Contractor: General Electric Co.
EPRI Project Manager: D. Sharma

HVDC Converter Transformer Magnetics
EL-4340 Final Report (RP1424-3); $32.50
Contractor: General Electric Co.
EPRI Project Manager: S. Nilsson

HARMFLO Code: Version 3.1
EL-4366-CCM Computer Code Manual (RP2444-1); $32.50
Contractor: Purdue University
EPRI Project Manager: J. Mitsche

Characteristics of Insulating Oil for Electrical Applications
EL-4381 Final Report (RP577-2); Vol. 1, $40.00; Vol. 2, $25.00
Contractor: McGraw-Edison Co.
EPRI Project Managers: S. Nilsson, E. Norton

ENERGY ANALYSIS AND ENVIRONMENT

Residential Load Forecasting for Small Utilities: Case Studies With Four Rural Cooperatives
EA-3805 Final Report (RP1985-1); Vol. 2, $32.50
Contractor: Burns & McDonnell Engineering Co.
EPRI Project Manager: J. Wharton

Sampling Design for Aquatic Ecological Monitoring
EA-4302 Final Report (RP1729-1); Vol. 1, $40.00; Vol. 5, $32.50
EA-4302-CCM Computer Code Manual; Vol. 2, $40.00
Contractor: University of Washington
EPRI Project Manager: J. Mattice

Strategic Planning and Marketing for Demand-Side Management: Selected Seminar Papers
EA-4308 Proceedings (RP2548-1); $40.00
Contractor: Battelle Memorial Institute
EPRI Project Manager: A. Faruqui

Combining Engineering and Statistical Approaches to Estimate End-Use Load Shapes
EA-4310 Final Report (RP2145-3); Vol. 1, $25.00; Vol. 2, $40.00
Contractor: Cambridge Systematics, Inc.
EPRI Project Manager: S. Braithwait

Annual Review of Demand and Conservation Research: 1984 Proceedings
EA-4313 Proceedings (RP1955-4); $62.50
Contractor: Battelle, Columbus Division
EPRI Project Manager: S. Braithwait

Demand-Side Planning: Case Study
EA-4314 Final Report (RP1820-4); $25.00
Contractor: Synergic Resources Corp.
EPRI Project Manager: J. Wharton

Biological Studies of Swine Exposed to 60-Hz Electric Fields
EA-4318 Final Report (RP799-1); Vols. 1, 5, and 7, $32.50 each; Vols. 2, 3, 4, and 6, $25.00 each
Contractor: Battelle, Pacific Northwest Laboratories
EPRI Project Manager: R. Patterson

Utility Approaches to Surveying the Commercial Sector
EA-4328 Final Report (RP1820-4); $25.00
Contractor: Synergic Resources Corp.
EPRI Project Manager: J. Wharton

Electric Utility Market Research Symposium
EA-4338 Proceedings (RP2050-11); $55.00
Contractor: Synergic Resources Corp.
EPRI Project Manager: J. Wharton

Value of a Power Plant's Remaining Life: Case Study With Baltimore Gas & Electric Co.
EA-4347 Final Report (RP2074-1); $25.00
Contractor: Temple, Barker & Sloane, Inc.
EPRI Project Manager: D. Geraghty

NERC Summary Load Forecasts: Retrospective Appraisal and Technical Analysis
EA-4355 Final Report (RP1153-10); $25.00
Contractors: National Economic Research Associates, Inc.; University of Washington
EPRI Project Manager: H. Chao

Remote and In Situ Detection of Atmospheric Trace Gases: Infrared Spectroscopy for Ammonia
EA-4370 Final Report (RP1370-1); $32.50
Contractor: SRI International
EPRI Project Manager: G. Hilst

Physiochemical Measurements of Soils at Solid-Waste Disposal Sites
EA-4417 Final Report (RP2485-3); $25.00
Contractor: Battelle, Pacific Northwest Laboratories
EPRI Project Manager: I. Murarka

ENERGY MANAGEMENT AND UTILIZATION

Heat Exchanger Requirements for Potable Water Protection
EM-4217 Final Report (RP2033-13); $32.50
Contractor: Fauske & Associates, Inc.
EPRI Project Manager: J. Calm

Demand-Side Management Information Directory
EM-4326 Interim Report (RP2548-1); $200.00
Contractor: Battelle, Columbus Division
EPRI Project Manager: A. Faruqui

Posttest Analysis of Beta (Na/S) Cells From Chloride Silent Power, Limited
EM-4341 Final Report (RP1198-15); $25.00
Contractor: Argonne National Laboratory
EPRI Project Manager: R. Weaver

Evaluation of Stratified Chilled-Water Storage Techniques
EM-4352 Final Report (RP2036-4); Vol. 1, $25.00; Vol. 2, $47.50
Contractor: University of New Mexico
EPRI Project Manager: C. Hiller

PRISM: A Conservation Scorekeeping Method Applied to Electrically Heated Houses
EM-4358 Final Report (RP2034-4); $40.00
Contractor: Princeton University
EPRI Project Manager: G. Purcell

Monitoring of Residential Groundwater-Source Heat Pumps in the Northeast
EM-4372 Final Report (RP1201-14); $25.00
Contractor: Allegheny Electric Cooperative, Inc.
EPRI Project Manager: P. Fairchild

Value-Based Utility Planning: Scoping Study
EM-4389 Final Report (TPS10-167); $25.00
Contractors: Levy Associates; Meta Systems, Inc.
EPRI Project Manager: C. Gellings

NUCLEAR POWER

Guidelines for Nuclear Plant Performance Data Acquisition
NP-3915 Final Report (RP2407-1); Vol. 1, $47.50; Vol. 2, $25.00
Contractor: Combustion Engineering, Inc.
EPRI Project Manager: N. Hirota

Compilation of Corrosion Data on CAN-DECON
NP-4222 Final Report (RP2296-3); Vol. 1, $32.50; Vol. 2, $32.50
Contractor: London Nuclear Ltd.
EPRI Project Manager: C. Wood

Set-Point Testing of Safety Valves Using Alternative Test Methods
NP-4235 Final Report (RP1811-1); $25.00
Contractor: Crosby Valve & Gage Co.
EPRI Project Manager: B. Brooks

Role of Coolant Chemistry in PWR Radiation-Field Buildup
NP-4247 Final Report (RP825-2); $32.50
Contractor: Westinghouse Electric Corp.
EPRI Project Manager: R. Shaw

Variables Influencing Radiation Fields at Four Pressurized Water Reactors
NP-4251 Interim Report (RP825-1); $25.00
Contractor: Babcock & Wilcox Co.
EPRI Project Manager: R. Shaw

Improvements in Motor-Operated Valves
NP-4254 Interim Report (RP2233-2); $32.50
Contractor: Foster-Miller, Inc.
EPRI Project Manager: B. Brooks

RETRAN-02 Benchmarking of the Nuclear Steam Supply System Transient Tests at Arkansas Nuclear One, Unit 2
NP-4263 Final Report (RP1385-2); $40.00
Contractor: Middle South Services, Inc.
EPRI Project Manager: J. Naser

Failures Related to Surveillance Testing of Standby Equipment: Emergency Pumps
NP-4264 Final Report (RP2471-1); Vol. 1, $32.50
Contractor: Mollerus Engineering Corp.
EPRI Project Manager: J. Matte

Effect of Boric Acid Treatment on the Secondary Cycle at ANO-2
NP-4270 Final Report (RP404-1); $32.50
Contractor: NWT Corp.
EPRI Project Manager: C. Welty

Application of Reliability-Centered Maintenance to Component Cooling-Water System at Turkey Point Units 3 and 4
NP-4271 Final Report (RP2508-2); $32.50
Contractor: Los Alamos Technical Associates, Inc.
EPRI Project Managers: J. Gaertner, W. Sugnet

BWR Owners Group Intergranular Stress Corrosion Cracking Research Program: Executive Summary, Phase 1 (1979–1983)
NP-4273-SR Special Report; $32.50
EPRI Project Manager: R. Jones

Assessment of Bolting Examination Requirements and Practices
NP-4274 Final Report (RP2179-5); $25.00
Contractor: Battelle, Pacific Northwest Laboratories
EPRI Project Manager: S. Liu

Seismic Equipment Qualification Using Existing Test Data
NP-4297 Interim Report (RP1707-15); $32.50
Contractor: Anco Engineers, Inc.
EPRI Project Manager: G. Sliter

LWR Core Materials Program: Progress in 1983–1984
NP-4312-SR Special Report; $32.50
EPRI Project Manager: D. Franklin

Fuel Consolidation Demonstration: Program Overview
NP-4327 Interim Report (RP2240-2); $25.00
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EPRI Project Manager: R. Lambert

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ADEPT: Acid Deposition Tree
Version 2.0 (IBM–PC)
Contractor: Decision Focus, Inc.
EPRI Project Managers: T. Wilson, R. Richels

EC&M: Energy Conservation and Management Model
Version 2.0 (IBM)
Contractor: United Technologies Research Center
EPRI Project Manager: D. Hu

EMPS: EPRI Methodology for Preferred Systems
Version 2.1R2 (IBM); EM-3919-CCM
Contractor: Arthur D. Little, Inc.
EPRI Project Manager: G. Purcell

FATIGUE: Torsional Fatigue Strength of Large Turbine Generator Shafts
Version 2.0 (IBM, VAX); EL-4333
Contractor: General Electric Co.
EPRI Project Manager: D. Sharma

MULTI–FLASH: Multiple-Phase Lightning Flashover of Transmission Towers
Version 1.1 (IBM–PC); EL-3608-CCM
Contractor: Power Technologies, Inc.
EPRI Project Manager: R. Kennon

TRADE: Transfer Capability Objective
Version 1.0 (IBM–PC); EL-3425
Contractor: Power Technologies, Inc.
EPRI Project Manager: J. Mitsche

WENS: Weather Normalization of Sales
Version 1.0 (IBM); EA-3143
Contractor: Battelle, Columbus Laboratories
EPRI Project Manager: Ahmad Faruqui

CALENDAR

For additional information on the EPRI-sponsored/cosponsored meetings listed below, please contact the person indicated.

APRIL

2–3
Industrial Applications of Adjustable-Speed Drives
Minneapolis, Minnesota
Contact: Marek Samotyj (415) 855-2980

8–10
Atmospheric Fluidized-Bed Technology for Utility Applications
Palo Alto, California
Contact: Stratos Tavoulareas (415) 855-2424

17–18
3d EPRI Reactor Physics Software Users Group Meeting
Braintree, Massachusetts
Contact: Walter Eich (415) 855-2090

21–22
Optimizing VAR Sources in System Planning
Washington, D.C.
Contact: Neal Balu (415) 855-2834

MAY

13–14
Reducing Cobalt in Nuclear Plant Materials
Seattle, Washington
Contact: Howard Ocken (415) 855-2055

JUNE

2–4
Conference: Life Extension and Assessment of Fossil Fuel Power Plants
Washington, D.C.
Contact: Barry Dooley (415) 855-2458

2–6
EPRI–EPA Joint Symposium: Dry SO_2 and Simultaneous SO_2-NO_x Control
Raleigh, North Carolina
Contact: George Offen (415) 855-8942

11–13
Probabilistic Methods Applied to Electric Power Systems
Toronto, Ontario
Contact: Paul Lyons (817) 439-5900

24–27
10th Geothermal Conference and Workshop: Expanding Capacity With Modular Systems
Portland, Oregon
Contact: Mary McLearn (415) 855-2487

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