Commercializing IGCC

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Cover: Southern California Edison Co.'s Cool Water demonstration plant has been the keystone for commercialization of integrated gasification–combined-cycle power plants.

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IGCC Commercialization

Spencer

Integrated gasification–combined-cycle (IGCC) systems are reaching the commercialization stage at a critical juncture in the evolution of the electric power industry. Several factors make the timing of these developments so significant. Foremost is the widespread concern for environmental quality. As the Cool Water station has demonstrated, IGCC technology can make electricity reliably and cleanly under the most stringent environmental constraints, even when fed with high-sulfur coal. This attribute is particularly timely in light of the current national focus on acid rain.

Financial risk reduction is a similarly important goal. Utilities need the option of adding new capacity in small increments, with short lead times, so as to match supply more closely with demand, to get new capacity into the rate base more quickly, and to incur less debt than is the case in the construction of large baseload plants.

Such incremental capacity expansion is possible with phased construction of IGCC plants—starting with combustion turbines for peaking capacity and adding a bottoming cycle and coal gasifier when more baseload power is needed. Potomac Electric Power Co. has already begun planning on a phased-in IGCC facility. Several other utilities who are members of the Utility Coal Gasification Association have conducted studies that show this approach is their least-cost option for capacity expansion.

Utilities today want technologies that offer resilience and flexibility in the face of uncertainties in fuel prices and supply, environmental legislation, and electricity demand. IGCC offers such flexibility: a plant can switch between oil, natural gas, and coal-derived gas to provide peak or baseload power as conditions warrant.

In addition to electricity generation, coal gasifiers have recently been put to commercial use for ammonia and methanol production and other chemical feedstock applications. The operating experience from these early systems is proving invaluable as the technology matures and gains broader application in diverse markets.

Commercialization of coal gasification technology did not happen by accident. It took more than half a billion dollars and a decade of cooperative R&D involving EPRI, Southern California Edison Co., other individual utilities, and equipment vendors to make Cool Water and other operating coal gasifiers commercially successful. The time, money, and talent invested in this task were well spent. It is now apparent that electric utilities, other industries, and especially the public will be reaping the benefits of this effort for many years to come.

Dwain Spencer, Vice President
Advanced Power Systems Division

Authors and Articles

Alpert Beardsworth Lindgren Wall Stepp Tang Kassawara Harry

IGCC: Phased Construction for Flexible Growth (page 4) details the flexibility in fuels, construction scheduling, plant size, and type of use that makes IGCC a lot more than a clean way to use coal for electricity production. Written by John Douglas, science writer, with assistance from EPRI's Advanced Power Systems Division.

Seymour Alpert has been technical director for the division for most of his 13 years with the Institute. He was with SRI International and Chem Systems, Inc., in the early 1970s, following 15 years with Hydrocarbon Research, Inc. ■

Measuring the Value of R&D (page 12) recounts an experiment, the process used, and especially, some important findings that can improve R&D payoff. Written by Ralph Whitaker, the *Journal*'s feature editor, with the cooperation of two members of EPRI's Research Applications staff.

Edward Beardsworth, appointed manager of benefit assessments this year, was formerly technology transfer administrator of the Energy Analysis and Environment Division. He joined EPRI in 1978 and until the spring of 1984 managed projects in energy conservation and load research. Previously, he was with Brookhaven National Laboratory for six years.

Nilo Lindgren, senior benefit assessment coordinator since 1982, has been a communications consultant and writer in the scientific community for 30 years. Between 1973 and 1976 he was manager of technical communications for the Palo Alto Research Center of Xerox Corp. Before that he was a cofounder of *Innovation* magazine; still earlier, he was on the editorial staffs of *IEEE Spectrum* and *Electronics*. ■

Breaking New Ground in Seismic Research (page 20) reviews extensive research conducted by EPRI to quantify seismic design margins, to learn more about soil-structure interactions, and to advance the practice of quake-resistant design. Written by Taylor Moore, senior feature writer of the *EPRI Journal*, and aided by four managers of risk assessment research in EPRI's Nuclear Power Division.

Ian Wall, the senior program manager, directs research activities that compose the Seismic Center. At EPRI since 1979, he was formerly with NRC for 4 years, becoming chief of the risk analysis branch. Still earlier, he was with the nuclear energy division of General Electric Co. for 10 years.

Carl Stepp, technical adviser, is responsible for seismologic research that contributes to the design of nuclear power plants. He came to EPRI in 1983, having been a senior staff member with Woodward-Clyde Consultants and, earlier, with Ertec Western, Inc. From 1973 to 1979 he was chief of the geosciences branch of NRC; before that he was with the National Oceanic and Atmospheric Administration for six years.

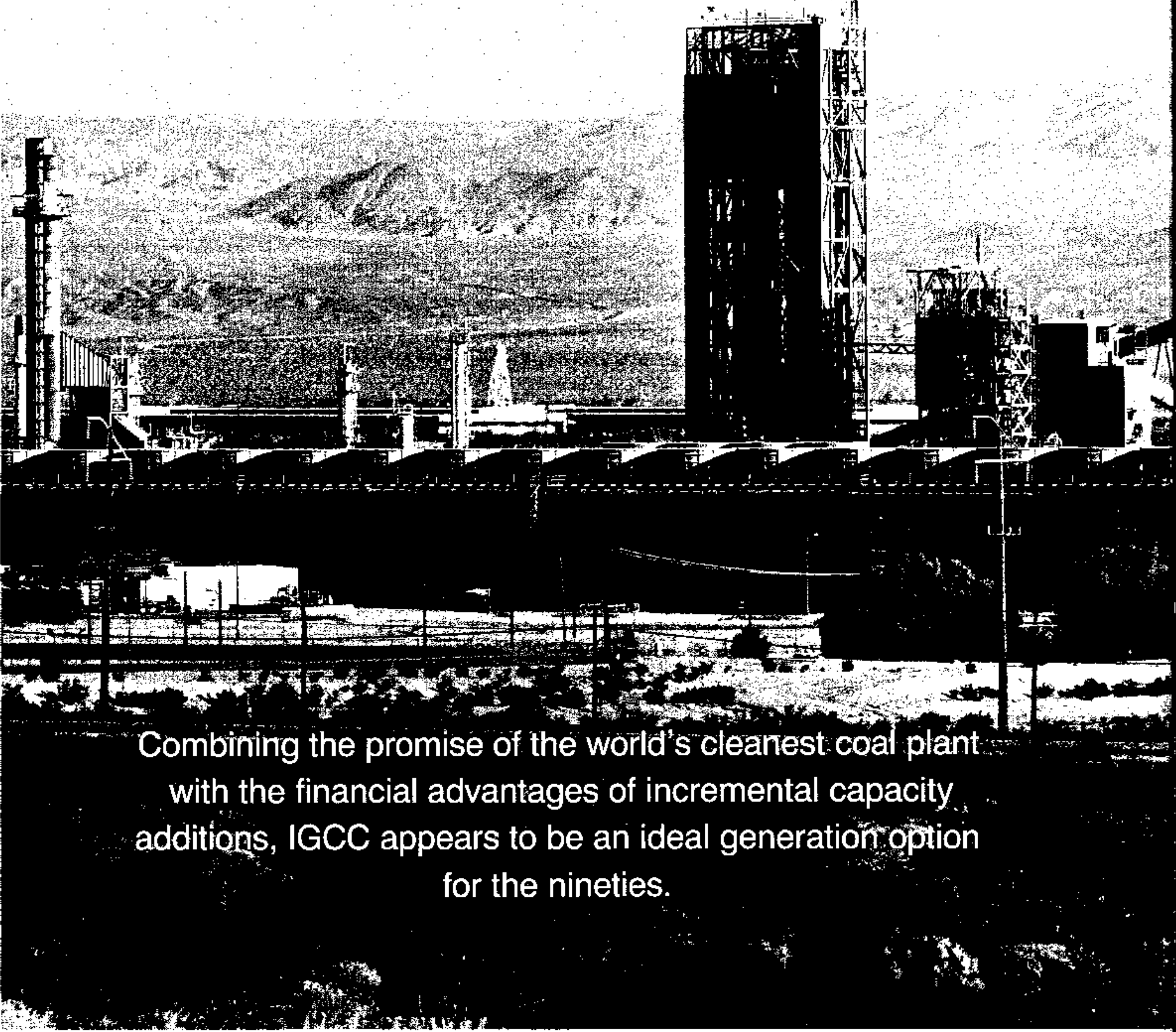
Hui-tsung Tang, subprogram manager for plant structural design research since 1981, joined EPRI in 1978 after six years with the nuclear energy division of General Electric Co., where he became a senior engineer and technical leader for nuclear containment technology.

Robert Kassawara, subprogram manager for postearthquake investigations, came to EPRI in 1985. He was formerly with Impell Corp. for four years, much of the time as manager of engineering analysis. Kassawara was with Combustion Engineering, Inc., from 1970 to 1981. ■

Heat Recovery for Restaurants (page 30) highlights a neglected heat recovery technology that can cut costs for restaurant owners and cut demand peaks for utilities. Written by Jon Cohen, science writer, with the assistance of EPRI's Energy Management and Utilization Division.

I. Leslie Harry, manager of industrial electrification, has guided projects in the electrotechnologies since he came to EPRI in 1980. He was formerly a consultant to Scientific Applications, Inc., and from 1971 to 1978 he was with the Department of Energy, successively in the nuclear program and as a program manager in the Office of Conservation. ■

IGCC Phased Construction for Flexible Growth



Combining the promise of the world's cleanest coal plant with the financial advantages of incremental capacity additions, IGCC appears to be an ideal generation option for the nineties.

When EPRI first began development of integrated gasification–combined-cycle (IGCC) power plants in the mid 1970s, the primary goal was to show that coal could be burned cleanly without the need for expensive, energy-wasting flue gas scrubbers. This goal has clearly been met in the 100-MW (e) Cool Water IGCC facility on the Southern California Edison Co. system near Barstow, California. For two years the plant has exceeded environmental and operational performance objectives, and it is now probably the world's cleanest coal-fired power plant. Because of this success, the immediate commercial potential of IGCC technology is being carefully considered by the recently formed Utility Coal Gasification Association, whose 37 member utilities represent approximately half of all U.S. generating capacity.

Even as the Cool Water facility was demonstrating the technical feasibility and environmental benefits of the IGCC concept, however, rapidly changing conditions within the electric power industry were making this technology appear even more attractive. Uncertain load growth and severe capital constraints created new incentives for utilities to add generating capacity in relatively small increments that can be built with short lead times. Currently low prices for gas and oil have also encouraged utilities to consider phased-in construction of new plants, which could initially use premium fuels for peaking duty and later switch to coal for baseload operation. The modular nature of IGCC plants makes them ideally suited for such incremental approaches. Over the long term, IGCC technology may also open new business opportunities for utilities through coproduction of chemicals and fuels.

"We believe that IGCC power plants show the greatest potential for meeting the stringent emissions standards that are likely to be placed on the use of coal in the near future," says Program Manager Neville Holt. "In addition, these plants can provide utilities greater flexibility in planning capacity additions during a period of great uncertainty in fuel prices and load growth. They may also revolutionize coproduction of electricity and high-value industrial chemicals."

Three basic choices

In a gasifier, coal reacts with oxygen and steam to produce a mixture of carbon monoxide, hydrogen, and other gases. Sulfur in the coal is converted to hydrogen sulfide during gasification, making it relatively easy to remove before the syngas is used as a fuel. The gasification reactions release considerable heat, which must be recaptured if electric power is to be generated efficiently. Also, for power generation, gasifier temperatures high enough to prevent formation of tars are preferred in order to minimize waste stream processing.

Three general types of gasifiers have evolved over the years, differing mainly in the way they mix coal with oxygen (or air) and steam. Each of these generic designs enjoys certain advantages under particular circumstances and all are undergoing commercial development by potential suppliers.

▫ In a moving-bed gasifier, pieces of coal about 0.125–2 in (3.18–50 mm) in size are introduced from the top of the reactor vessel and move slowly downward. Steam and the oxidant gas blow upward through the solids, while the syngas product stream leaves the vessel through an opening above the bed of coal. Ash can be withdrawn as either a dry solid or a molten slag. One advantage of this design is that the relatively slow movement of coal results in a high degree of carbon utilization, but temperatures in the top parts of the reactor are low enough to also allow the formation of tars.

▫ Fluidized-bed reactors use coal that is ground into particles 2 mm or less in diameter so they can be suspended by a swiftly moving stream of oxidant gas and steam from below. The operating temperature is more uniform throughout the reactor vessel than in moving-bed gasifiers, but it must be carefully controlled so as to remain low enough to keep ash from fusing, yet high enough to prevent formation of tar. One problem with fluidized-bed gasifiers is that the upward velocity of gases is great enough to carry very fine coal particles out of the reactor vessel in the syngas stream. In some designs these particles are recycled to increase carbon utilization.

▫ Coal for an entrained-flow gasifier is pulverized to form particles approximately 0.08 mm in size, which may be mixed into a water slurry or fed dry into the reactor vessel. The oxidant is blown into the vessel adjacent to the coal so that gasification begins immediately and continues as the convergent stream of reactants moves rapidly downward to the gasifier exit. Temperatures are high enough to prevent formation of tars and to fuse the ash into particles of slag that can be removed from the bottom of the vessel. Entrained-flow designs can generally handle large through-puts of coal with high utilization of carbon.

Birth of a second generation

The first generation of such gasifiers were used during the 1920s and 1930s to produce synthetic liquids and gases for use as fuel and feedstock. Most of these industrial gasifiers operated at nearly atmospheric pressure and had much smaller capacities than units needed for power production. Development of larger, more-efficient gasifiers has been under way for the last decade, and several of these second-generation technologies are now approaching commercialization. EPRI is participating in some of these development projects in order to assess the potential various types of advanced gasifiers may have for use in IGCC power plants.

The furthest advanced of the second-generation technologies is the Texaco gasification process, which is based on entrained flow and uses oxygen and a coal-water slurry fed through a coaxial nozzle. The Texaco gasifier at the Cool Water project has the capacity to gasify 1000 t/d of coal. Heat produced during gasification is recovered to produce high-pressure steam as the syngas moves through two 36-m-high coolers. The gas is then cleaned and burned in a combustion turbine to produce about 65 MW of electric power, while heat from the combustion turbine exhaust gases is recovered to produce more steam. The two lines of steam are then combined to power a 55-MW steam turbine. Of the gross 117 MW produced, approximately 20 MW are used on-site. The balance is sent into the grid of Southern California Edison, which is the host utility. The electricity supply from the plant provides electric service for about 100,000 homes in its service territory. The energy required at the plant includes the power needed to produce oxygen at an over-the-fence air separation plant. The Cool Water facility also has a spare quench gasifier, which douses the syngas and coal slag with water to cool them. Use of this quench gasifier can increase plant availability during maintenance work.

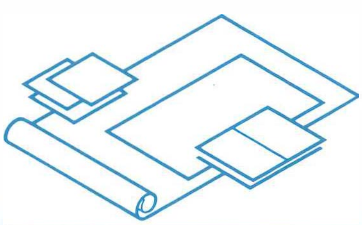
In addition to the Cool Water facility, in which EPRI is the lead partner, the Texaco entrained-flow gasifiers are also being used commercially at three industrial sites. Two 900-t/d quench units began operation in 1983 in Kingsport, Tennessee, using Appalachian coal for methanol production. Four 500-t/d units are producing syngas for ammonia manufacture in Japan. And an 800-t/d gasifier with a single cooler is due to start operation this year in West Germany for chemical feedstock production.

EPRI is also a full partner in a pilot plant that uses the Shell Oil Co. entrained-gasification process. In this process, dry coal and oxygen are fed into a gasifier through multiple burners, and the syngas product is removed at the

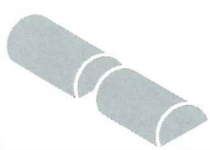
Phasing-In IGCC

One possible phase-in sequence is shown. Phased construction offers flexibility in the face of uncertain load growth and minimizes cost and risk. This approach allows each new increment of capacity to be brought into the rate base quickly and defers investment in the most costly part of the system (the gasification plant) until it is justified by fuel economics.

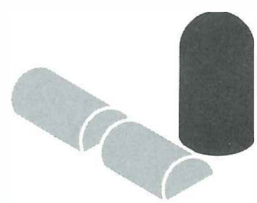
Phase I
Planning



II
Combustion turbines



III
Combined-cycle



Action

Phase I: Planning for modularity builds flexibility into expansion plans.

II: Peak demand is met most economically with combustion turbines fueled with natural gas or oil.

III: Steam cycle added to create high-efficiency combined-cycle plant for intermediate and baseload service.

Capacity (MW)

Modular approach allows small increments of capacity to be added as needed.

	II	III
By component	125 / 125	125 / 125 / 110
Total	250	360

Total capital cost per kW (1985 $)

Planning costs are modest in comparison with plant construction and operation.

II	III
280	500

top of the gasifier, rather than from the bottom, as in the Texaco process. Heat from gasification will be recovered to produce steam in a syngas cooler. The pilot plant, located at Shell's research center in Deer Park, Texas, is scheduled to begin operation early next year. EPRI will gather data on the process to help evaluate its suitability for use in an IGCC power plant.

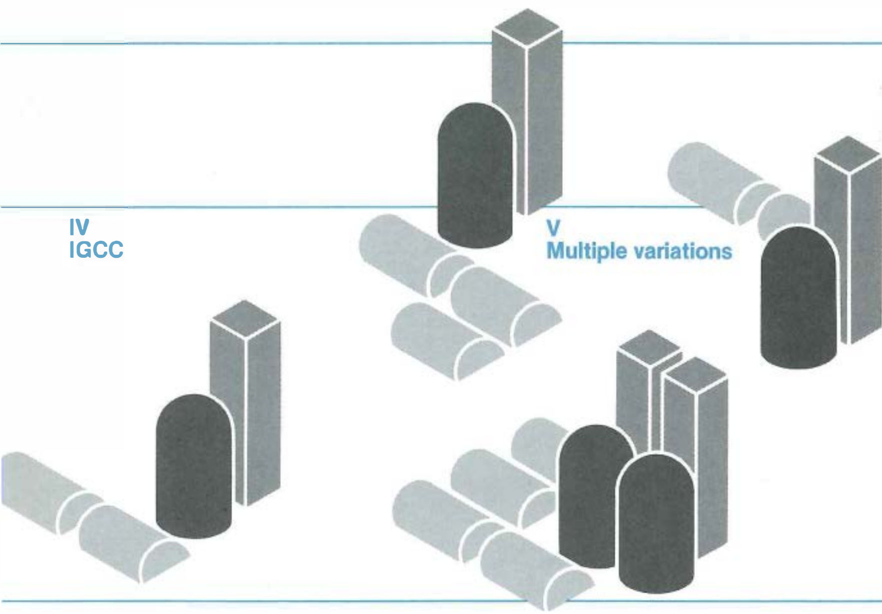
A 600-t/d moving-bed gasifier developed jointly by British Gas Corp. and Lurgi began operation earlier this year in Westfield, Scotland.

A 30-MW combustion turbine has been installed to generate electricity from the syngas produced at this commercial-prototype plant. EPRI, Gas Research Institute, and British Gas will conduct a test program with U.S. coals at the plant. Allis-Chalmers Corp. has also built an air-blown 600-t/d rotating-bed gasifier, and EPRI is participating in the test.

The only other IGCC power plant now under construction in the United States is being built by Dow Chemical Co. in Louisiana. This process uses a slurry-fed entrained gasifier. The plant will produce 160 MW (net) of electricity. EPRI staff is monitoring the project.

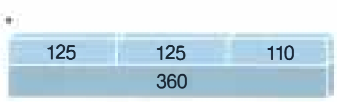
Preliminary studies indicate that entrained-flow gasifiers offer some advantages for power production, particularly the quick response they provide for load following and their lack of tar. Shell's entrained-flow process can probably handle the widest range of coal, but Texaco's single-burner configuration appears simpler to build and operate. Among the major IGCC contenders, the British Gas–Lurgi moving-bed gasifier appears to make the most efficient use of coal, but some recycling is needed to eliminate the tars it produces. Second-generation fluid-bed gasifiers for IGCC applications have not yet approached commercial status and are still being developed.

Compared with standard pulverized-coal plants equipped with flue gas desulfurization, each of the leading IGCC candidates promises to be competitive in terms of both capital and operating



Gasification facility added to run plant on coal-derived gas when oil and natural gas prices rise.

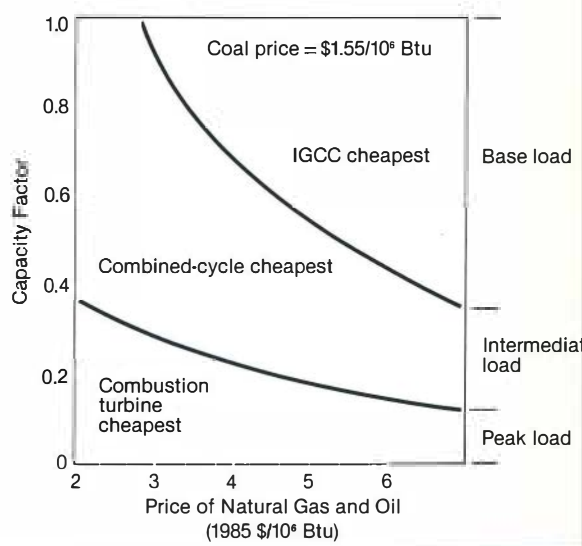
Any number of configurations can be phased-in as warranted by demand and fuel cost.



*The gasification facility adds no capacity but does raise the capital cost in enabling the plant to run on coal.

Minimizing the Cost of Electricity

Electricity cost is a function of the plant's capital cost, fuel price, and capacity factor—the fraction of the time the plant is operated. Although they burn traditionally expensive fuel (natural gas or oil), combustion turbines are cheaper to operate for peak power production (low-capacity factor) because they have a low capital cost. Combined-cycle plants (also burning natural gas or oil) are the most economical in a wide range of capacity factors because they are very efficient. A utility may run the facility as a combined cycle indefinitely, waiting to add a coal gasification plant if and when coal is sufficiently cheaper than natural gas or oil to justify the investment.



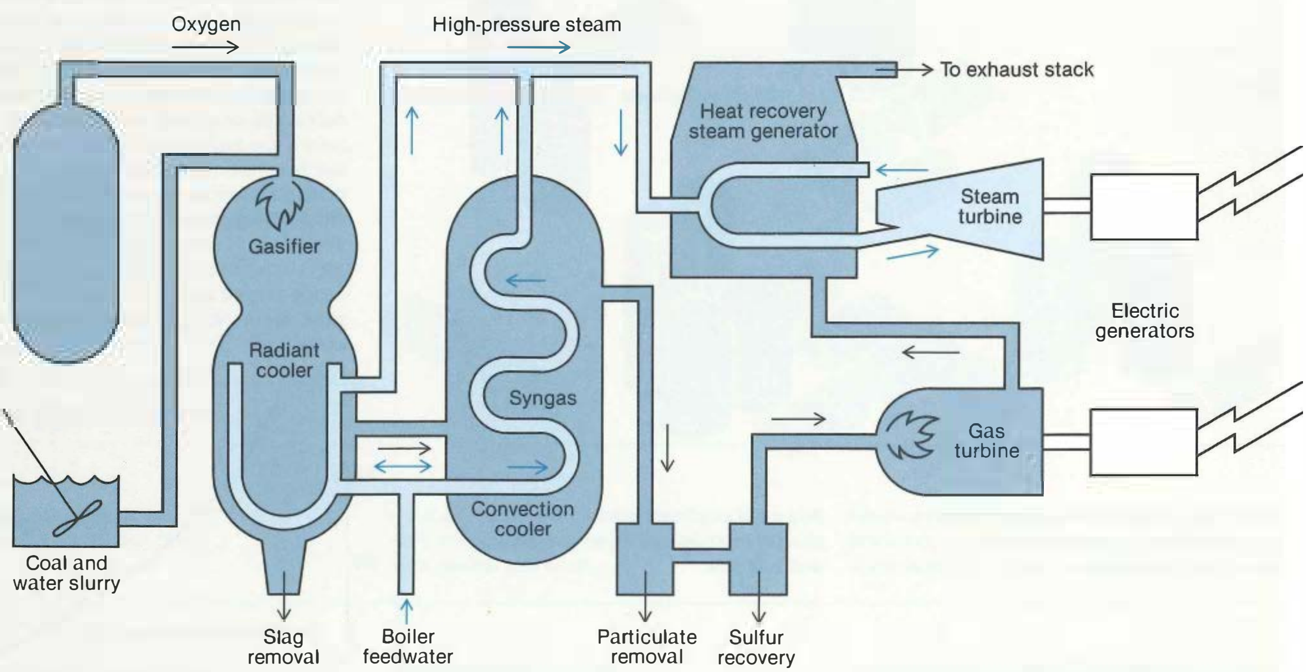
costs. For a 500-MW plant coming online in the late 1980s, the levelized cost of producing electricity at a constant capacity factor of 65% has been estimated at 48 mills/kWh for a conventional coal plant, 48 mills/kWh for Texaco IGCC, 47 mills/kWh for Shell, and 47 mills/kWh for British Gas–Lurgi. In each case the IGCC plant would have significantly lower emissions of sulfur and nitrogen oxides and significantly better heat rates than a conventional coal-fired plant. Equally important, however, will be the additional flexibility that IGCC technology offers utilities for tailoring plants to fit individual circumstances.

Meeting utility needs

IGCC plants have unique features that give them advantages beyond a simple cost comparison with conventional coal plants. Because sulfur removal is an inherent and relatively inexpensive part of the gasification process, IGCC plants can take advantage of high-sulfur, lower-cost coals. They can also be designed to meet even more stringent environmental control requirements with only minor cost increases. Commercial IGCC plants will consist of a number of parallel gasification trains, so if any one line is out of service, power generation can continue at a reduced level. Even if the entire gasification system is unavailable, the combined-cycle power generation system can be fired with fuel oil or natural gas. The availability of IGCC power plants is therefore expected to be approximately 90%, significantly better than the availability of equivalent conventional coal plants.

The ability of IGCC plants to burn supplemental fuel will also enable utilities to select designs most suited to their own peak load patterns. Although the gasification section of a plant is virtually unaffected by outside air temperature, the power generating capability of a gas turbine decreases rapidly as ambient temperature rises. A turbine with a 133-MW capacity at 20°F (−7°C) may be able to produce only 104 MW at 88°F (31°C). The capacity of the gasification section and the use of supplemental fuels can thus be chosen to provide maximum power generation on either warm or cold days.

A utility with sharp load peaks in the summer, for example, could choose to



IGCC: How It Works

Dozens of coal gasification processes exist. One of them, the entrained-gasification process shown here, is used at the Cool Water IGCC facility. A coal-water slurry reacts with oxygen to form raw syngas. As the gas cools, the heat it releases produces high-pressure steam. The gas is cleaned of slag, particulates, and sulfur (sold as a by-product) and then burned in a combustion turbine to produce electricity. Steam from the syngas coolers and heat from the combustion turbine exhaust produce saturated steam in the heat recovery steam generator. The saturated steam then drives a steam turbine generator to produce additional electricity.

build sufficient gasification capacity to fully load a plant's turbines at lower temperatures; gas or oil could be cofired to meet the extra fuel demands of the turbines as they operate at peak efficiency. The attractiveness of this strategy would depend on the amount of capital saved by building a smaller gasifier, compared with the cost of purchasing supplemental fuel.

Various gas cooling options can also be chosen, depending on how a new plant would be used. At Cool Water, gas and slag from the gasifier fall through a radiant cooler, in which the slag solidifies and is collected from a lockhopper at the bottom. The gas then passes through a convection cooler before it is treated for sulfur removal. One or both of these coolers might be omitted by having the gas quenched with water either immediately after leaving the gasifier or after passing through the radiant cooler. The choice depends on a trade-off between capital costs and plant efficiency. A more efficient plant—that is, one that uses less heat to produce a given amount of power—is preferentially dispatched. Thus a utility could choose the heat rate of a new IGCC plant according to the frequency with which it would be dispatched for service.

An economic and performance analysis of the three gas cooling options was conducted for EPRI by Fluor Engineers, Inc., assuming a Texaco gasifier and an advanced General Electric Co. combustion turbine. "The new turbine is scheduled for commercial introduction in the late 1980s, a time they need it most," says Seymour B. Alpert, technical director, Advanced Power Systems Division.

"In addition to providing a choice among various configurations to meet particular needs," Alpert continues, "an IGCC plant provides modularity, which enables a utility to add capacity in increments that closely match load growth and to even construct a plant in phases, if desired."

Phased construction

Whenever a new power plant is constructed, a utility must place considerable capital at risk by spending, borrowing, or otherwise committing funds to a project. Because conventional coal and nuclear technologies exhibit considerable economies of scale, new baseload plants have often been built in units of 1000 MW, or more. Such plants not only require placing very large sums of capital at risk before power is ever generated but they often give a utility generating capacity substantially above its current needs. Customers sometimes also receive a rate shock when a large, expensive plant comes on-line and electricity rates are adjusted to allow for funds committed during construction.

Because of its modular nature, IGCC technology can be incorporated into much smaller plants without substantially increasing the capital cost per kilowatt of capacity. A 400-MW plant, for example, could be built with two relatively independent IGCC trains. Because each train would contain a combustion turbine that could generate power with oil or gas, however, construction of a plant could begin with installation of just the turbines, allowing the gasification and combined-cycle systems to be added later in phases. Such phased construction would enable a utility to match load growth very closely by adding units in roughly 100-MW increments. Capital placed at risk during any single phase would not only be much less than if funds were spent all at once for a complete IGCC plant but there would be an additional advantage in that the plant could begin earning new revenue while construction of later phases was in progress.

A scenario for phased construction of a 400-MW plant might go something like this. A single 120-MW combustion turbine would be installed and begin generating power with oil or natural gas. Such a turbine using premium fuels could be employed in peaking duty and would be limited to 1500 h/yr of operation under provisions of the Fuel Use Act. As demand for electric power grew, a second turbine could be added under similar conditions. The third phase would involve adding two heat recovery steam generators and a steam turbine. Heat from the combustion turbines, which would previously have been lost, would thus be recovered and used to generate 125 MW in a highly efficient combined-cycle system. During the third phase, some additional natural gas could be fired in ducts leading to the steam generators if they were built with enough capacity to handle heat recovery from gasification in the final phase of construction.

Once load growth warranted addition of more capacity and conversion of the plant to baseload operation, a gasification system could be added. Because this fourth phase would cost somewhat more than the first three phases combined, phased construction would enable a utility to postpone its largest commitment of capital to a new baseload plant as long as possible. The gasification system envisioned for a 400-MW plant would probably consist of two or three parallel gasifiers and coolers.

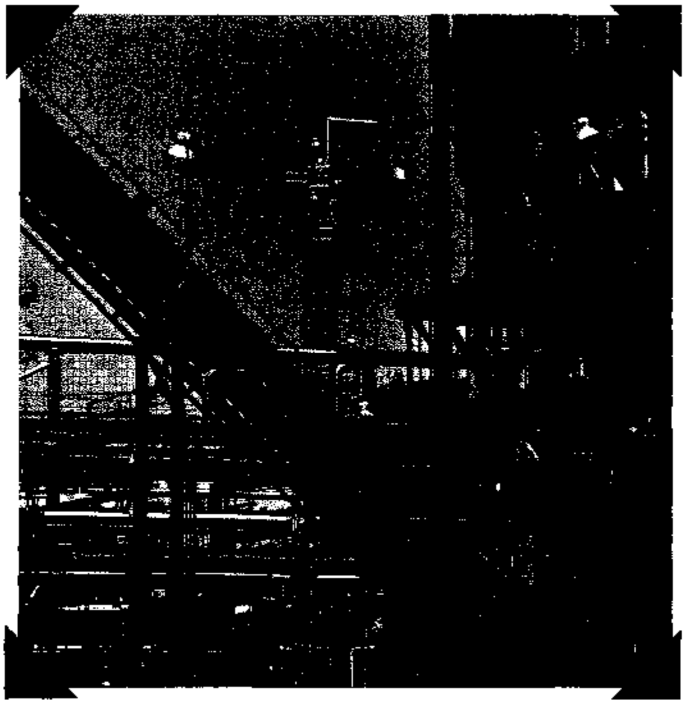
In addition to its inherent benefits for matching load growth and deferring capital expenditures, phased construction could also prove a particularly useful strategy during a period of low prices for premium fuels. In 1985 the price of coal was about $1.55/million Btu, and that of natural gas was about $3.50/million Btu. Under such conditions, combustion turbines fired with natural gas provide the lowest-cost electricity for plants with capacity factors below about 25%. For plants operating with capacity factors in a very wide range above this level, combined-cycle systems using natural gas would be the most economical. Coal plants (either conventional or IGCC) would not become competitive for capacity factors less than about 80%.

Phased construction, with its rapid

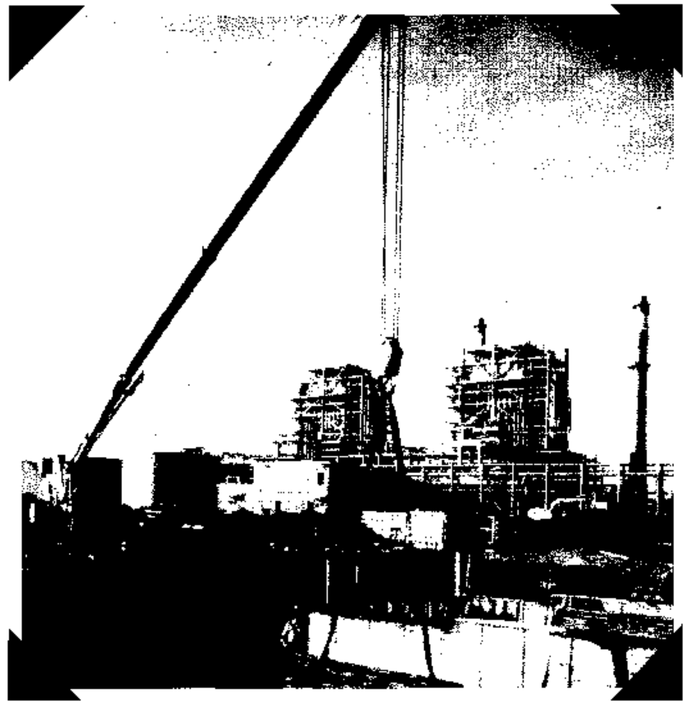
Commercializing Gasification Technology

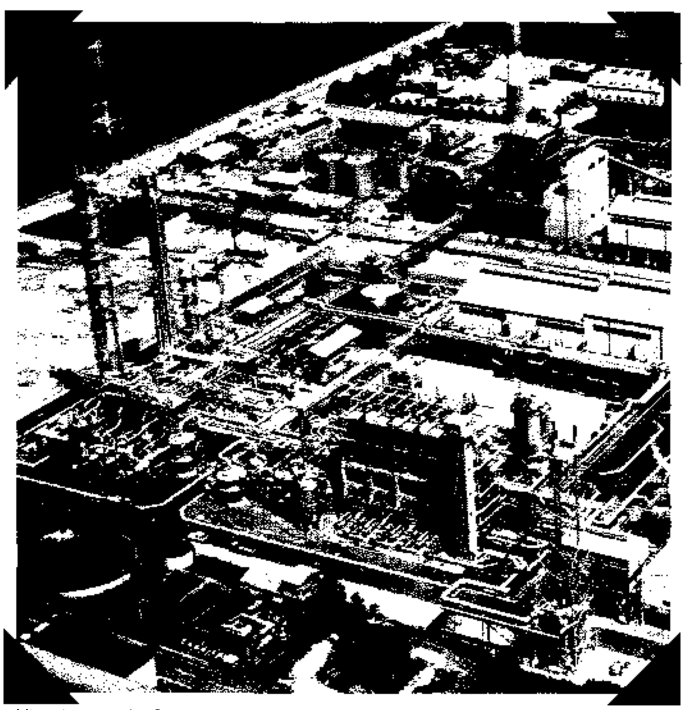
Several pioneering coal gasification facilities are paving the way for commercialization of this technology for both power generation and industrial processes. The Cool Water plant is the nation's first full-scale utility IGCC facility. The Deer Park demonstration gasification plant now under construction will start producing synthetic gas and steam in 1987 at Shell Oil Co.'s Deer Park, Texas, manufacturing complex. The Ube Ammonia Co. plant, completed in 1984 in Ube City, Japan, processes 1000 t/d of coal to generate synthetic gas used in ammonia production. The IGCC plant now under construction by Dow Chemical Co. will provide 160 MW (net) of electricity for Dow's chemical complex in Plaquemine, Louisiana.

Cool Water

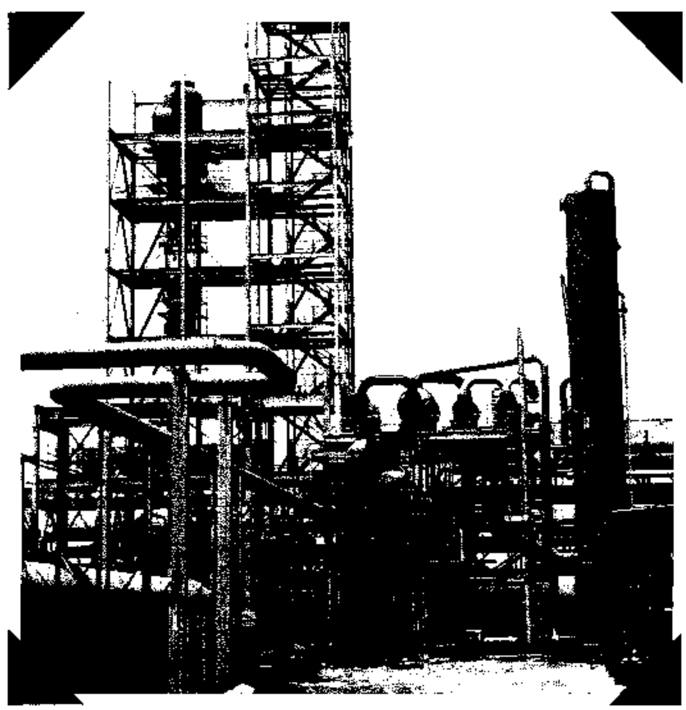


Deer Park





Ube Ammonia Co.



Dow Chemical Co.

installation of combustion turbines and combined-cycle systems, would thus enable utilities to accommodate load growth by using premium fuels when their prices are attractive. When gas and oil inevitably become more expensive because of their limited resources, however, the switch to coal could be made relatively easily by adding a gasification system to the existing plant.

EPRI studies indicate that phased construction of IGCC plants could provide utilities with a substantial saving in capital investment, while lowering the ultimate cost of generating electricity. For a 500-MW plant, phased construction of an IGCC plant would save an estimated \$130/kW compared with building a conventional coal-fired power plant and \$260/kW compared with an unphased IGCC plant (in constant 1985 dollars). A separate study by General Electric indicated the possibility of even greater economic advantages for phased construction of IGCC plants, with capitalized savings of \$350–\$750/kW compared with the cost of building conventional coal plants.

As a result of such potential advantages, 16 utilities are already conducting or planning to conduct site-specific IGCC design studies. One of these utilities, Potomac Electric Power Co., has announced tentative plans to construct a phased IGCC power plant on the basis of its own study showing that such a plant would offer savings with an approximate present value in excess of \$100 million. The first combustion turbine of the proposed plant is scheduled to come on-line in the early 1990s, and the final gasification phase is to be completed by 1997.

Opportunities for the future

Although the immediate attractiveness of IGCC plants to utilities may be related to their flexibility and potential for phased construction, the greatest long-term benefits still lie in their superior ability to burn coal cleanly. An IGCC power plant emits about one-tenth the acid precipitation precursors (oxides of sulfur and nitrogen) than does a pulverized-coal plant, while producing only 40% of the solid wastes. The importance of such considerations is bound to rise with the increased concern over acid precipitation and the higher cost of solid-waste disposal.

Recently, President Reagan and Canada's Prime Minister Mulroney endorsed the Lewis-Davis report acknowledging acid rain as an international problem and calling for funding of \$5 billion to demonstrate advanced emissions control technologies for coal-fired plants. "I believe this agreement provides a tremendous opportunity for government and industry to share the first-of-a-kind risks associated with IGCC plants," comments Dwain F. Spencer, vice president, Advanced Power Systems. "From past experience, we can expect that the initial busbar costs for electricity from the first few plants may be 10–20% higher than the eventual costs from mature plants. Risk-sharing by the federal government would help alleviate utility and public utility commission concerns over the introduction of a new technology, while substantially helping the international effort to control acid precipitation. In addition, because IGCC plants can accommodate high-sulfur coals, such a program would provide new jobs in several of this country's most depressed coal mining regions."

The benefits of IGCC technology for disposal of solid wastes have also been demonstrated at the Cool Water facility. Elemental sulfur with a purity of 99.9% is now being produced at the plant and is being sold for more than \$100/t. The solidified slag particles, which have a texture of coarse sand, are recognized as nonhazardous by the test procedure of the California State Department of Health. A program is under way to use the slag particles in road construction, among other uses.

Another long-range prospect for IGCC plants owned by utilities is the production of liquid fuels or chemical feedstocks. Methanol, for example, can be produced by catalytic reaction of the hydrogen and carbon monoxide present in syngas. Such conversion of the syngas could be conducted efficiently during off-peak hours at an IGCC power plant, and the methanol could be used either as a fuel for other peaking plants or as a feedstock for the commercial production of such materials as acetic acid, formaldehyde, and single-cell protein. The high octane value of methanol also makes it attractive as an additive to gasoline. And a commercial process exists for converting carbon monoxide and hydrogen directly into ammonia for fertilizer production.

The sale of such coproducts could help utilities cap the price of electricity during periods of higher premium fuel prices. "I believe utilities will increasingly come to see themselves as energy and related-products companies, rather than just entities for the generation, transmission, and distribution of electricity," reports Dwain Spencer. "Integrated coal gasification–combined-cycle plants offer the electric power industry a unique opportunity for achieving this transition." ■

Further reading

Planning Data Book for Gasification–Combined-Cycle Plants: Phased Capacity Additions. Final report for RP2029-13, prepared by Fluor Engineers, Inc., January 1986. EPRI AP-4395.

"IGCC Phased Capacity Addition." *EPRI Journal,* Vol. 10, No. 10 (December 1985), pp. 50–54.

M. J. Gluckman et al. "Commercial Potential for Texaco-Gasifier-Based Combined-Cycle Power Plants." In *Proceedings of the 12th Energy Technology Conference,* Washington, D.C., 1985, pp. 1432–1441.

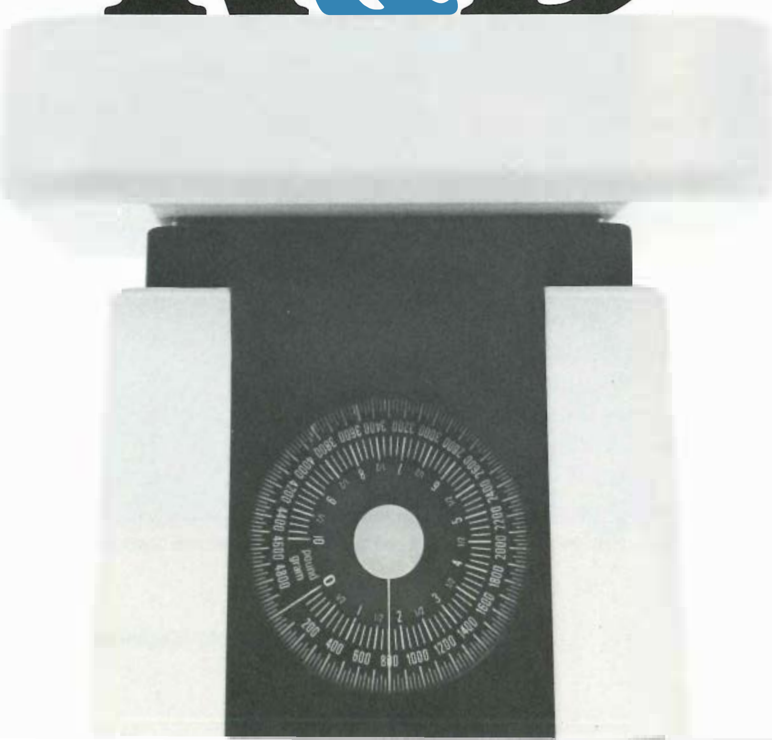
Cost and Performance for Commercial Applications of Texaco-Gasifier-Based Combined-Cycle Plants, 2 vols. Final report for RP2029-10, prepared by Fluor Engineers, Inc., April 1984. EPRI AP-3486.

Coal Gasification Systems: A Guide to Status, Applications, and Economics. Final report for RP2207, prepared by Synthetic Fuels Associates, Inc., June 1983. EPRI AP-3109.

This article was written by John Douglas, science writer. Technical background information was provided by Seymour Alpert, Advanced Power Systems Division; additional support by Neville Holt and Michael Gluckman.

Does EPRI's research pay off for its members? A study undertaken with 24 member utilities to quantify the return on R&D investment shows that it does, with benefits exceeding costs in every case.

Measuring the Value of R&D



Few of us question that industrial research is necessary and worthwhile. But when business is slow and competition is sharp, when production capacity is idle or not cost-effective, companies take a hard look at their R&D budgets, at least questioning the size and short-run relevance of the investment. "How soon does it pay off?" they ask, and "How well?" or "Can we measure the benefit we get?"

Such questions are particularly apt among EPRI's member utilities because some of them support only the nationwide R&D program planned and managed by EPRI. It is one thing for a utility to assess the return on research it has commissioned or conducted on its own account; it is another to quantify the return on its investment in a cooperative program.

So questions of exact R&D benefit persist. Utility managements ask them. Regulatory bodies ask them. EPRI on several occasions has helped its members compile answers, usually on a case basis. A little more than a year ago, EPRI asked the questions on its own.

For EPRI, assessing utility R&D benefit seemed a way of gauging its service to members and perhaps also of evaluating their alertness to the opportunities and benefits available. Objective measurement techniques might prove to be consistent and thereby permit standardization and useful comparisons.

Taking inventory of all a utility's R&D applications would also illuminate technology transfer—the complex of actions and communications and relationships between EPRI and its members that move R&D results from the pages of reports into practice on utility systems.

The experimental effort is now complete, a benefit assessment campaign conducted cooperatively over a period of six months with two dozen of EPRI's more active members. The objective was to quantify each utility's return on its investment with EPRI. Wherever possible, figures were worked up for each new technology adopted—how much it cost and how much it saved. Then an overall benefit-cost ratio was derived for the utility—typically, the net savings from all its new applications relative to the cumulative cost of its EPRI membership.

Among the 24 utilities, overall benefit-cost ratios range from 1.2:1 to 7.6:1. Each utility's figures for its own new technology applications and practices are internally consistent, but an average figure for the 24 utilities cannot be derived because of variations in assessment criteria, assumptions, and calculation methods.

Comparisons of experience between utilities, even for the same technology, are likewise difficult to draw. However, the fact that all the ratios are positive, despite differences in calculation, strengthens EPRI's conviction that its work can pay off measurably for any member. R&D is no longer simply a long, methodical line of inquiry into the future. It can be seen as a real-time aid in solving current utility operating problems.

Also, the Institute's product pipeline is only now really flowing full, and technology transfer is only now becoming truly aggressive. These facts suggest that utility benefits—by any measure—can only go up in the years to come.

Sense as well as dollars

Quantitative payoff is only part of the story, however. As an important collateral conclusion, the 24 utilities uniformly insist that indirect and qualitative benefits are at least as important as the objective and quantitative ones. In fact, an important lesson from the experimental campaign is that focusing on the benefit-cost ratios of easily defined hardware can easily obscure or minimize many qualitative and indirect contributions of R&D.

Texas Utilities Electric Co., for example, concludes that fully three-fourths of its measurable benefit from EPRI's base program R&D has been in fuel cost savings, the outcome of better availability (hence greater capacity factors) at several plants that have low generating costs. The improved availability in turn stems from applying several EPRI-sponsored advances in subsystem reliability and O&M practice.

But availability also contributes to operating flexibility, a benefit that Texas Utilities considers as strategically important, although it is not easily measured. "Some strategic options are enhanced by the cumulative effects of applied research products where benefits have been quantified," says the Texas report. "A significant example of this is the unquantified value on a system basis of increases in availability of individual generating units."

The cooperating utilities in this, the first concerted effort, included 20 investor-owned companies, 3 municipal utilities, and 1 rural cooperative. They ranged from the Texas Utilities system, with its 1984 peak load of 15,265 MW, down to the Athens (Tennessee) Utilities Board, a small municipal service with a 1984 top of 85 MW. For all these utilities, and also for EPRI, there was a consciousness of leaving behind the "better mousetrap" theory that R&D results will always find automatic acceptance on merit alone.

In particular, the campaign found EPRI decisively casting itself in the role of marketer for the first time. This was a crash course in such activities as researching the market, gauging its readiness, measuring market penetration, forecasting product acceptance, testing sales strategy, formulating customer appeals, lining up endorsements, and analyzing the bottom line performance of products and services.

On the basis of a handshake and a confirming exchange of correspondence between each utility chief executive or general manager and EPRI's president, Floyd Culler, teams of EPRI member service, research application, and technical program staff members set out to identify and calibrate the utilities' true R&D interests. They were armed with nine specially assembled catalogs that listed some 500 items of hardware, software, diagnostic technique, assessment methodology, manuals and guides, test facilities, and data bases.

Did each utility's inquiry into its assimilation of R&D really flow smoothly from an initial telephone conversation with Floyd Culler of EPRI? Did the campaign outcome meet expectations? Did it reveal new needs, either in technology R&D or in the relationship between utilities and EPRI? Discussion with a pair of EPRI team leaders yields a composite account of the campaign.

Edward Beardsworth, now manager of benefit assessments, and Nilo Lindgren, the senior assessment team leader, focus on the process involved—a process that had to be followed consistently for all utilities, yet be flexible in execution and able to evolve somewhat during the six-month campaign. Essentials of the process were developed in discussions between Lindgren and Wayne Seden, EPRI's manager of research applications and the 1985 campaign director. Beardsworth and Conway Chan were then drawn from EPRI's technical divisions to add professional depth and head two of the four assessment teams.

Finding people and time

The ideal sequence began (two to four weeks after front office agreement was established and documented) with a planning meeting of utility and EPRI program leaders. An identification phase followed for a month or six weeks, giving the utility time to ferret out all possible examples of its actual or potential use of EPRI research results. This was a time of intelligence gathering.

The next milestone, a profiling workshop, brought together all utility and EPRI participants, including as many as 8–10 resource people from EPRI's technical staff to answer questions and clarify technology issues. The intent here was to clear the way for an analysis phase, the utility's hard-nosed assessment, in dollars wherever possible, of every instance of EPRI technology it had evaluated or put into practice. This phase included a lot of telephone traffic as utility and EPRI

Participants in Benefit Assessment

Utilities were chosen, in part, to represent diversity in geographic distribution, ownership, generation mix and fuel use, and size. The figures given are 1984 peak demand.

1 Athens Utilities **(88 MW)**
2 Boston Edison **(2515 MW)**
3 Carolina P&L **(7799 MW)**
4 Cleveland Electric **(3371 MW)**
5 Commonwealth Edison **(14,572 MW)**
6 ConEdison **(7435 MW)**
7 Delmarva P&L **(1682 MW)**
8 Florida P&L **(10,384 MW)**
9 Houston L&P **(11,198 MW)**
10 Kentucky Utilities **(2193 MW)**
11 Lincoln Electric **(435 MW)**
12 Nevada Power **(1537 MW)**
13 New York State E&G **(2253 MW)**
14 Northern States Power **(5544 MW)**
15 Pacific Gas & Electric **(14,224 MW)**
16 Pennsylvania P&L **(5519 MW)**
17 Public Service E&G **(7422 MW)**
18 Puget Sound P&L **(3481 MW)**
19 Salt River Project **(2260 MW)**
20 Southwestern Electric Power **(2948 MW)**
21 Texas Utilities **(15,265 MW)**
22 United Power Assn. **(471 MW)**
23 Virginia Power **(8895 MW)**
24 Wisconsin Electric **(3684 MW)**

personnel, now on a first-name basis, engaged in easy give-and-take to round out the utility's benefit documentation. As often as not, this was also a time to pick up threads of personal interaction that would lead to new transfers of technology.

If needed, a wrap-up meeting was scheduled, where some of the earlier utility participants organized the findings and assigned authors to various sections of the report. The report phase itself followed—understandably the most varied in length because of the range of detail and depth chosen by different utilities.

This kind of benefit assessment program was first seen as a tentative and experimental exercise with a sample of EPRI's membership. It was urgent only in that everyone wanted an early answer on the validity of the process. But the campaign soon became more intensive and more extensive than anyone at EPRI expected. It ate up the full time of three research applications team leaders, and it engaged one-third to one-half the time of 8 or 10 technology transfer administrators and other temporarily designated specialists from EPRI's technical divisions.

The campaign also dominated the lives of EPRI's 9 member service representatives, who shared with the team leaders the intricate planning and liaison needed to carry out 24 overlapping travel and workshop schedules. Finally, more than 100 EPRI research managers were called upon at different times to take part in one or more of the profiling workshops.

For many of the utilities also, the time requirements dawned progressively. Planning meetings proved unexpectedly helpful in this connection. This occasion brought together the utility's assigned senior executive, its assessment program leader (preferably the utility's technical information coordinator, or TIC), EPRI's team leader, and EPRI's member service representative. Their joint task was to establish objectives and lay out schedules, develop and explain procedures and documents, delineate roles and responsibilities, and make individual assignments.

These activities sometimes began piecemeal, by telephone, before the planning meeting, even to the point that a utility had already begun its internal canvass for examples of EPRI research results in use or under evaluation. Just as often, however, the planning meeting revealed that the best-intended commitment by a utility's top management was not an automatic ensurance of smooth sailing.

Relatively few utilities, in fact, had intelligence-gathering organizations in place before the planning meeting. In those cases, TICs had already surrounded themselves with deputy or department coordinators, as a routine way of carrying out their responsibility. But far more of them were just starting to do so, using the benefit assessment program as a motivator. For most utilities, ad hoc groups had to be created.

Thus, some delays were circumstances of inconvenient timing and some were the result of lapses in communication. Eventually, a utility's "half" of an assessment might come to involve half or all of its TIC's time for three or four months, a month or more of time for several coordinators (typically 1 to 6 people, but in some cases more than 12), and from one to three days for 50–150 engineers and other technical staff members.

"On average, everyone took twice the originally expected time," reports Lindgren. But utilities were not alone in their miscalculation. "We were innocent, too," he recalls, mostly in terms of juggled airline reservations and other travel plans. This also affected the half-dozen or more EPRI research managers who had to be assigned, then reassigned, to rescheduled profiling workshops.

Such organizational logistics and communications involved less travel for utilities but far more calls and memoranda among many staff members. Perhaps the sole exception was the Athens (Tennessee) Utilities Board, a TVA distributor and the smallest of the participants. Even its five R&D reviewers would have been outnumbered by EPRI visitors at a profiling workshop, so two Athens staff members tucked their 112 candidates for benefit assessment into briefcases and traveled to EPRI's California offices for the occasion.

Differences in calculation

The profiling workshop was the culminating, although not final, event of each benefit assessment. As the only time all the players came together, this was an opportunity to clarify all manner of questions about the definition, application, or evaluation of R&D results. In some instances it also proved to be an inspirational overview of the entire process, and at this point responsibility shifted completely from EPRI to the utility.

Weeks earlier EPRI had raised the essential questions and compiled the data base, set the process in motion, and facilitated its conduct. Together, EPRI and the utility coordinators had "shaken up the organization"—someone's phrase for encouraging a new urgency of R&D awareness and creating the informal network of R&D-related communication that had identified the utility's R&D applications. After the workshop, that new network remained intact in most cases, and the benefit assessment report began to take shape.

By mid 1986 all the reports were complete, although a few were still undergoing executive review. The wide range of benefit-cost ratios (from 1.2:1 to 7.6:1) is most easily explained in terms of the different yardsticks used to assess benefits. These variations showed up especially among the great number of informational products in EPRI's guides, catalog–manuals, data bases, software, test data, seminars and workshops, and so on.

For instance, one utility's reviewer would evaluate the benefit gained from a manual by its official EPRI price tag (say, $25), another would go by the consulting cost that the manual precluded (easily $50,000 or more), and a third reviewer would instead tally the utility's eventual savings from following the manual in system design and hardware selection (perhaps millions of dollars).

Treatment of the time value of money also introduced qualitative and quantitative differences in reported benefit-cost results. Continuing benefit values varied from simple averages over a few years to formal present-value calculations over an economic lifetime.

The utilities were expected to be generally conservative in their benefit and cost assessments, and they were, with variations in degree. But apart from that, some were hesitant to claim a benefit share at all, even for very tangible improvements, when several interrelated R&D project results were involved. Part of the problem, for example when assessing power plant availability improvement, was in pinpointing the specific source of improvement.

To some extent this results from an engineer's training to look at all the variables, to avoid a black/white, either/or characterization of cause and effect—"This technology is only part of the answer." But also behind the hesitancy at times was a reluctance to assign credit for an innovation—"It would have come about some other way." At its worst, this was the not-invented-here syndrome.

Either way, EPRI team leaders and utility TICs became uncomfortable when the built-in emphasis on numbers seemed likely to inhibit personal interactions and new acquaintances. They acknowledged that the process was designed to quantify benefits, but largely as a means to the more important goal of better communication in technology matters.

Another difficult determination for the utilities was their indirect benefit from EPRI research on such industrywide environmental topics as acid rain, waste

Pacific Gas and Electric Co.

nuclear, hydro, oil generation; approximately 63.4 billion kWh annual sales

PG&E uses about 40% of EPRI's products, an impressive portion, but found that only 13 products account for more than two-thirds of benefits realized. Major examples include guidelines for improving PWR water chemistry and CORA-II, a computer model of PWR corrosion transport. PG&E's nuclear and hydro generation is widely scattered in a large service territory, so equipment and methods for design and maintenance of T&D systems showed up strongly: computer-aided transmission line design and testing, power pole stubbing, pole rot and tree growth retardants, and metal oxide surge arresters. Adjustable-speed motor drives for power plant auxiliaries and test kits for residual PCB detection in transformers also figured in PG&E's findings.

disposal, risk management, or PCB toxicology. This assessment was most troublesome where a utility had little or no capital investment to be directly affected. Some reviewers felt that the uncertainties, number of assumptions, and ultimate imprecision in such instances overwhelmed the credibility of whatever value they might assign. Accordingly, there was a wide range of responses.

Indirect and future value

Even where quantification was clearcut (the majority of cases), it stimulated utilities in their consciousness of indirect benefits. It also motivated them to search out and acknowledge purely qualitative benefits. This allayed earlier concern, when the 1985 campaign was planned, that benefit-cost assessment might give too much prominence to bottom line thinking about short-term R&D and perhaps discourage utility support of issue-oriented investigations, long-range programs, and high-risk research.

Refreshingly, several utility reviewers and final report writers expressed themselves very positively on this point. John Molberg, the R&D coordinator of Cleveland Electric Illuminating Co., for example, mentioned reduced costs throughout the industry, enhanced technical skills, enlightened regulation, and spinoff technologies and then wrote, "Such benefits are likely to be more significant than direct benefits like hardware and software, but indirect benefits are not reliably quantifiable, so they tend to be forgotten." Molberg's concluding sentence is the telling one. "To discourage such oversight, indirect benefits are given top billing in this report."

Not far removed from indirect benefits that are difficult to quantify are benefits to flow in the future from R&D that is not yet complete. After 14 years of work, EPRI is now completing about 100 developments each year that are directly usable by utilities. In particular, a number of major products and systems with long lead times are just coming to fruition (such as improved heat pumps, amorphous metal transformers, and atmospheric fluidized-bed combustion) or are not far in the future (such as electric vehicle batteries, fuel cells, and highly efficient photovoltaics).

Consolidated Edison Co. of New York, Inc., dealt consciously and directly with this issue, concluding that 36% of its cumulative EPRI membership cost applied to incomplete and long-term R&D. The company therefore chose to neglect that portion when calculating today's benefit-cost ratio.

At least one utility staff member cautioned that benefit assessment simply may not be a forward-looking methodology. "If you focus excessively on the return from past investment, and neglect the future," he said at a campaign follow-up meeting, "you begin to foreclose options. As options are closed off, utilities begin to relinquish control of their own destinies."

Observations like these raise questions about the relationship between benefit-cost quantification and technology transfer. Does one cause the other, or measure it accurately? Why was quantification so predominant in EPRI's 1985 campaign?

Almost universally, the utilities acknowledge that taking inventory served a purpose. The urgent focus on evaluation and the forced personal interactions stimulated an awareness of R&D assimilation as perhaps nothing else would have. Utilities even uncovered the existence and use of some EPRI-sponsored advances for the first time, notably those that are now part of product lines available from established industry suppliers.

But it is becoming just as widely evident that benefit quantification is not the ultimate measure of technology transfer. It is only the means to a greater end. A benefit assessment is a status report at one moment; technology transfer is a two-way process with a life of its own.

Today, when costs and competition (and the regulatory responses to both) are forcing some utilities to evaluate their direct and indirect support of R&D, a thoughtful and thorough benefit assessment can produce a credible figure for the value received by a utility. But over a span of time, the main value of that same benefit assessment is the new patterns and practices of R&D information transfer and evaluation that are set in place. These are what create the climate for intentional, continuous technology transfer. Several observations from the 1985 campaign can therefore be useful to the far greater number of EPRI's member utilities that did not take part.

First, utilities that devote organizational time and resources to their relationship with EPRI get the most from their membership investment. Such portfolio management especially means giving attention to internal communications, horizontally as well as vertically, making sure that gaps are closed be-

Carolina Power & Light Co.

coal and nuclear generation; approximately 34.4 billion kWh annual sales

CP&L found most of its R&D benefit in new technology to avoid outages and to improve the efficiency and availability of its nuclear and coal generating units. The biggest winner in recent years has been a cluster of 12 products for dealing with cracking in BWR pipe systems. Failure rate analyses to preclude forced outages for tube leaks in coal-fired boilers were also noted. Two more winners were techniques for evaluating the remaining life of turbine rotors and safety/relief valve tests to meet NRC requirements. In the coming five years, CP&L foresees doubling its benefits from the use of R&D products for improved plant performance and availability.

CP&L

tween those who can use information on new technology.

Second, a strong TIC is central to this effort and to the flow of information itself. The position needs clearly stated organizational authority and responsibility. Also, the individual in the position needs personal authority, so as to find the "real" community of potential R&D users and draw them together in an effective communication network.

Third, EPRI's identity, its work, its resources, and its relationship to the utility need to be thoroughly explained if utility technical staff are to tap into Institute expertise on an ad hoc basis.

Finally, as in the 1985 benefit assessments, vigorous, visible, personal leadership by the utility's number-one executive is key in forming new patterns and

WORKSHOP INTERACTION

The profiling workshop was the most powerful single occasion of a benefit assessment. This was when all the intelligence gathered during the identification phase came together for the first time, not only on paper but "in person." At some utilities there was even an element of pageantry as the purpose, the scope, and the value of an intensive effort became widely evident—a shared awareness of R&D that almost became an organizational overlay.

In one room were anywhere from 50 to 150 individuals—all the utility's technology reviewers, its network of department coordinators who had directed them, the TIC and program leader, the designated senior management executive, and in many cases, the utility's chief executive officer or general manager. Joining them were their EPRI counterparts—research managers from each technical division, plus EPRI's team leader, its member service representative, and a senior Institute executive.

A welcome by the utility CEO reinforced the priority of the joint effort. It also was a vehicle for his acknowledging the work already done and urging both speed and care in the analysis phase. Even at this point, despite careful groundwork, an individual might be sitting in for the first time—on the strength of a phone call or memo the day before—preparing to identify R&D applications on the spot and put numbers on an assessment worksheet.

Next, EPRI's team leader summarized alternative approaches to benefit and cost calculations. And the utility TIC described concurrent sessions to follow, where EPRI researchers would act as resources in broad topic areas. Utility staff members would move from one session to another as necessary, rounding out their information for specific assessments.

Nilo Lindgren, EPRI's senior team leader, notes that EPRI's research managers were also uniformly trained in the quantification methods used to establish benefit-cost ratios. And Edward Beardsworth, also a team leader and now manager of benefits assessment, adds that a training consultant helped them brush up their presentation and communication skills.

But both men emphasize that "this was not the place for a dog-and-pony show about any program. The intent was simply to sit at a table with utility counterparts and work together, principally exploring ways to assess technologies, and quantifying whenever possible."

In contrast to the highly focused beginning of a profiling workshop, the ending was often casual to the point of defying definition. The EPRI team leader and the TIC circulated among conference rooms, facilitating discussions. Sometimes these blew hot; sometimes they blew cold. But eventually all the questions had been asked, the utility engineers returned to their offices and laboratories, and the EPRI researchers one by one closed up shop and departed for the airport, perhaps heading home, perhaps to another workshop.

EPRI's team leader and member service representative, the TIC, and sometimes other utility coordinators gathered up the loose ends. Over dinner that night or breakfast the next morning, they assigned action items to each other, especially including followup with technical colleagues on details the utility would need to complete all assessments and get started on its report. □

Virginia Power

coal and nuclear generation; approximately 41.8 billion kWh annual sales

Virginia Power cited major benefits from R&D-based improvements in its coal-fired and nuclear power plant operations but noted extensive benefit also in T&D throughout its three-state service territory. These areas of R&D use (and also load management and conservation) follow from company strategy to defer major construction until the 1990s. Nearly half of the Virginia Power benefits are from use of PWR water chemistry guidelines, and most of the rest are traceable to five products: gas-in-oil monitors on main stepup transformers, metal oxide surge arresters, a chemical cleaning manual, techniques for creep life assessment in pressure parts, and new ASME code guidelines.

practices of R&D communication. Stating utility policy and priority, the CEO or general manager gives endorsement and direction, and he can provide inspiration, too.

A climate for new technology

Such watchwords seem straightforward and obvious, and they are. If they suggest anything new, it is the value of informal communication networks. Utility officers and members of EPRI's industry advisory committees, for example, often have long-standing and close relationships with members of EPRI's executive staff. Similarly, but entirely separately, utility TICs and technical staff members work beneficially with EPRI research managers in the context of specific and often comprehensive R&D applications.

Even these showcase circumstances were improved during the benefit assessments, as new networks laced various

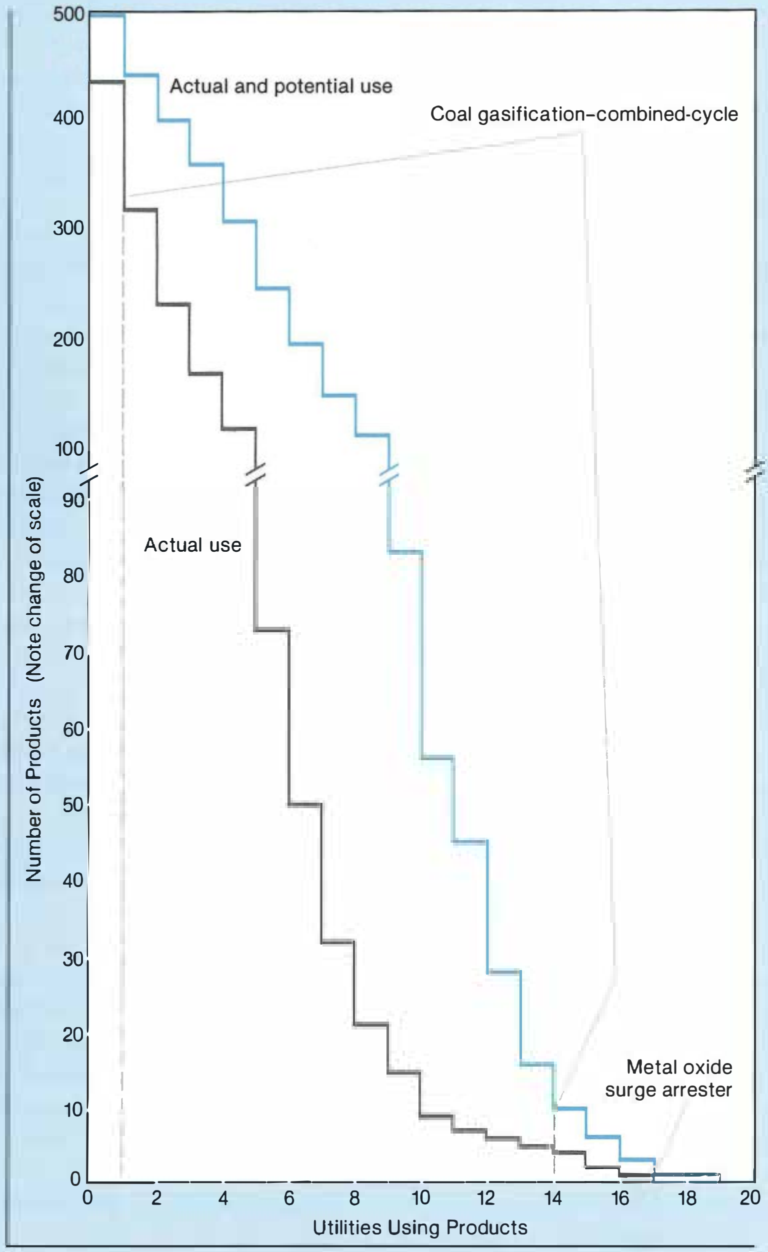
Boston Edison Co.

oil and nuclear generation; approximately 11.8 billion kWh annual sales

Boston Edison serves a heavily populated metropolitan area with a generation mix that is two-thirds oil- and gas-fired and one-third nuclear. As with other utilities that made assessments, it draws major benefit from relatively few R&D products, most of them addressing power generation. New technology for improved performance of fossil fuel plant subsystems and components (boilers, condensers, feedwater heaters, pressure parts) drew mention, as did in-service training for nuclear plant inspection personnel. The latter, in particular, enabled Boston Edison to defer an outage until its regularly scheduled time.

Use of R&D Products

Stairsteps denote the acceptance of 500 R&D products—everything from entire power generation technologies down to disposable test kits; included are subsystems and apparatus, components, computer software, environmental research results, and a variety of manuals. Best sellers (the most widely used products) are at the lower right, the metal oxide surge arrester having 17 citations for actual use. Big winners (denoting high payoff for the user) can show up anywhere. Product rankings will change with time. For example, the big-ticket coal gasification-combined-cycle technology has only one use today (EPRI's Cool Water demonstration plant in California) but rates 14 citations when potential uses are considered.



groups together—top level and working level, line and staff, field and office, engineering and operations. (EPRI saw some of the same kinds of new ties form among its R&D planning and project management people.)

EPRI played a catalytic role in this process—planning and facilitating meetings, bringing in resource people, and so on. And TICs did much to clarify it, especially at the outset. It was one thing for utility management to have a clear perception of EPRI as an R&D agency; it was another thing for working engineers to accept a demanding, whirlwind regimen of inquiry into their programs, decision processes, and daily activities. To everyone's credit, all the utilities (and practically all the individuals) came to an understanding of the process and its goals that yielded success for all the participants.

The outcome of the 1985 benefit assessments was clearly positive (EPRI COM-4803-SR). Was this a process that could or should be continued, intact, into 1986 or 1987? Reviewing the campaign origins and objectives gives one answer. Reviewing its labor intensity and schedule-driven inflexibility gives another.

Evolved and carried out in only about eight months early last year, the campaign responded to a 1984 review of EPRI's effectiveness, conducted by its Board of Directors. Among other items, the Board recommended that EPRI exercise stronger leadership in technology transfer, that it accelerate the adoption of R&D results among utilities. This new policy emphasis was welcome, and the acquaintances and team spirit built last year, within EPRI and 24 utilities, are a testimonial to new technology transfer capabilities on both sides.

But for EPRI's other 500-plus member utilities, does the comprehensive benefit assessment have sufficient appeal for continued use? Last year, with electricity loads growing slowly in a hotly competitive climate, EPRI reasoned that measures to justify R&D cost would draw favorable attention. Also, the idea of identifying and measuring immediate and near-term return on what is traditionally seen as a long-term investment seemed especially intriguing.

Candidate utilities for benefit assessment were hand-picked from among EPRI's more active members. Success among such utilities might be seen as predictable, and nobody at EPRI argues the point. Lindgren points out compelling reasons for EPRI's action. "One was to demonstrate what is possible in technology transfer, not just the average of what is actually taking place today. We wanted to encourage others to do better.

"Also," he adds, "because this was an experiment, we needed to choose utilities where we could count on the CEO to clear a path of time priority with his people."

Top-level involvement was thus the key that opened the benefit assessment effort at each utility. In a few cases, it is true, that key did not turn easily. The 24 utilities of the 1985 campaign were thus selected from a larger list of candidates, and this is a signal that benefit assessment is not a universal means of stimulating technology transfer. It is also true that the success of 1985 created a waiting list of other utilities.

Most important, perhaps, quick calculation showed that the campaign could not continue without change. At 24 assessments every year—an exhausting pace—it would take from 16 to 20 years to cover EPRI's membership. Activities in 1986 have had to take a different turn.

Only a few of the 18 assessments requested or in progress this year are using the full-scale, comprehensive process of 1985. There was a widespread desire to avoid such an inherently rigid, unified, and all-encompassing exercise. Utilities want more flexible and adaptive efforts directed to their specific circumstances and needs.

Clearly, the comprehensive benefit assessment is over. In a very short time it proved that R&D pays off for any utility that puts its mind to the matter. Corollary to that observation was the realization that a more widely aggressive or conscientious R&D monitoring effort among EPRI's members would startlingly raise the industrywide R&D benefit-cost ratio.

The campaign proved that a utility organization and its internal R&D communication patterns can be constructively shaken up and reformed on short notice. But continuous assignment of EPRI resources to the task is not in the cards for everyone, simply because of manhour and membership numbers. Utilities with the 1985 campaign experience behind them, however, can be peer models. Given these demonstrations, others can build their own new R&D awareness and thereby take better advantage of the new technology options they command by their EPRI membership. ■

This article was written by Ralph Whitaker. Technical background information was provided by Edward Beardsworth and Nilo Lindgren, Corporate Communications Division.

United Power Association

coal generation; approximately 5.5 billion kWh annual sales

UPA, a generation utility, screened EPRI's complete product list on behalf of its membership of distribution cooperatives, turning up 36 R&D products used or in use. Generation-related benefits include new technology for coal ash disposal, baghouse operation, and flue-gas desulfurization chemistry. T&D benefits pertain to transmission tower pier design, wind-induced galloping of overhead lines, and control of power system network dynamics. A big winner in the future is likely to stem from UPA's effort, in cooperation with EPRI, to develop an effective and low-cost heat storage furnace that will ease the winter peak demand on UPA's system.

Breaking New Ground

Although nuclear plants are designed to safely withstand earthquakes, new perceptions of seismic hazards in the East are leading utilities to reassess the margin of seismic safety at plant sites. EPRI research is helping to resolve uncertainties and advance scientific understanding of earthquakes and their effects.

A century ago, on the night of August 31, 1886, an earthquake that is estimated to have been Richter magnitude 7 shook the area of Charleston, South Carolina, claiming over 100 lives and severely damaging many buildings there and in nearby towns. The main shock was felt in Boston, New York, and Milwaukee and as far as 1000 mi (1610 km) away in Bermuda. Ever since, most experts have considered the quake's origins tied to anomalous local geology.

Yet to this day—and despite prodigious strides in scientific understanding of the origin and mechanisms of earthquakes—seismologists and geologists have been unable to definitively pin the cause of the Charleston earthquake on a particular, unique local geologic feature. In the absence of clear evidence of such previously assumed geologic uniqueness and after nearly a decade of study, U.S. Geological Survey (USGS) concluded in 1982 that the possibility of earthquakes similar in scale to the Charleston event could not be ruled out for much of the rest of the eastern United States.

Clarification by USGS on the seismic potential east of the Rocky Mountains prompted the Nuclear Regulatory Commission (NRC) and utilities that operate nuclear power plants to reevaluate earthquake hazards at eastern plant sites. Although nuclear plants are designed and built to withstand maximum local earthquakes, the recent change in perception of the risk of a Charleston-like earthquake has led to efforts to quantitatively estimate probabilities of seismic ground motions at nuclear plant sites and to demonstrate the margin of seismic safety in reactor designs.

EPRI is at the heart of this effort, working with utilities, NRC, and USGS to better understand the eastern seismic potential and nuclear plant safety margins, as well as to advance the state of the art of earthquake engineering with improved knowledge of the interaction of soil and structures during earthquakes. Since 1983 the Seismic Center established within the Nuclear Power Division's Safety Technology Department has been a focal point for EPRI's research (some of which began as early as 1979) aimed at resolving seismic safety issues, advancing the technology related to earthquake engineering, and developing more-realistic seismic design criteria.

"There is wide consensus in the nuclear and earthquake engineering communities that to compensate for inadequate data in every aspect of seismic design, nuclear plants have been built and licensed for 20 years under extremely conservative criteria that give them ample—and perhaps excessive—margins to withstand earthquakes much larger than the design or Safe-Shutdown Earthquake," says Ian Wall, EPRI senior program manager for risk assessment. "Unfortunately, the degree of conservatism has not been quantified and now, with the change in the technical position of USGS on the seismic potential in the East, many utilities face reassessment of plant seismic margins despite continuing uncertainties." Helping to clarify and quantify those uncertainties is a major thrust of EPRI's seismic research.

Seismic hazard: a closer look

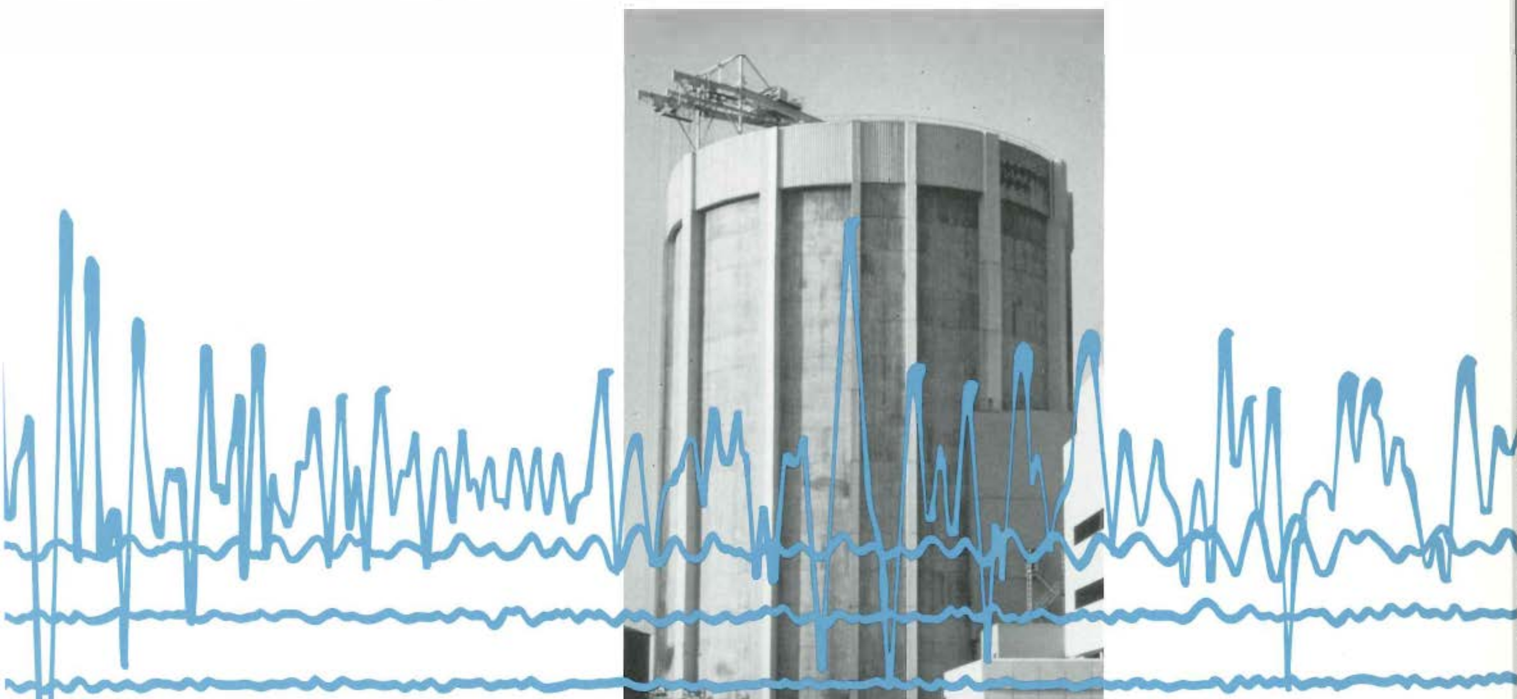
Most Americans probably think of California in connection with earthquakes, but the largest and potentially most damaging earthquakes in this country include several that occurred east of the Rockies. Three temblors in 1811–1812 in the upper Mississippi River valley near New Madrid, Missouri, are estimated to have been of a Richter magnitude greater than 8 on the basis of observed effects, placing them in the class of the 1906 San Francisco earthquake. The New Madrid and Charleston earthquakes affected areas much larger than comparably sized events in the West; in the case of New Madrid, casualties and damage were slight only because of the sparse population in the area at the time.

In the West the underlying causes of earthquakes are fairly well understood. The strong ground motions and surface faulting are manifestations of the alternating buildup and occasional release of tremendous energy in the earth's crust that results from the opposing movements of the Pacific and North American tectonic plates. Generalized predictions of the location and frequency of earthquakes in the West are now possible, thanks to steady advances in seismology, particularly in the last 20 years.

But the seismic hazard picture east of the Rockies is much less clear. Although scientists have identified a potentially major seismic source zone in the area of the New Madrid earthquakes that includes Memphis, Tennessee, the sources of earthquakes throughout the East are not generally known. Although mechanisms of earthquakes in the East are believed to involve release of intraplate stresses (within the North American plate), these are poorly understood both because of the slim historical earthquake record (lower frequency of occurrence) and limited knowledge of the deep geology in eastern North America. Eastern earthquakes are felt over much wider areas than those in the West because the energy they release is attenuated less as it travels through rock and soil.

On balance, experts say, the overall seismic hazard in the East is less than in the West, although the greater efficiency of seismic wave propagation partially offsets the East's lower frequency of earthquake occurrence.

Traditional utility and regulatory practice in siting and seismic design for most existing nuclear plants assumed large historical earthquakes were geographically stationary, meaning that the likelihood of recurrence of major seismic events around New Madrid or Charleston was believed limited to those areas. J. Carl Stepp, former chief of geosciences at NRC who now directs EPRI's seismic hazard research as technical adviser in the Risk Assessment Program explains, "Although the deep geologic structure is unknown, scientists held the view that earthquakes would keep occurring in the same place.



in Seismic Research

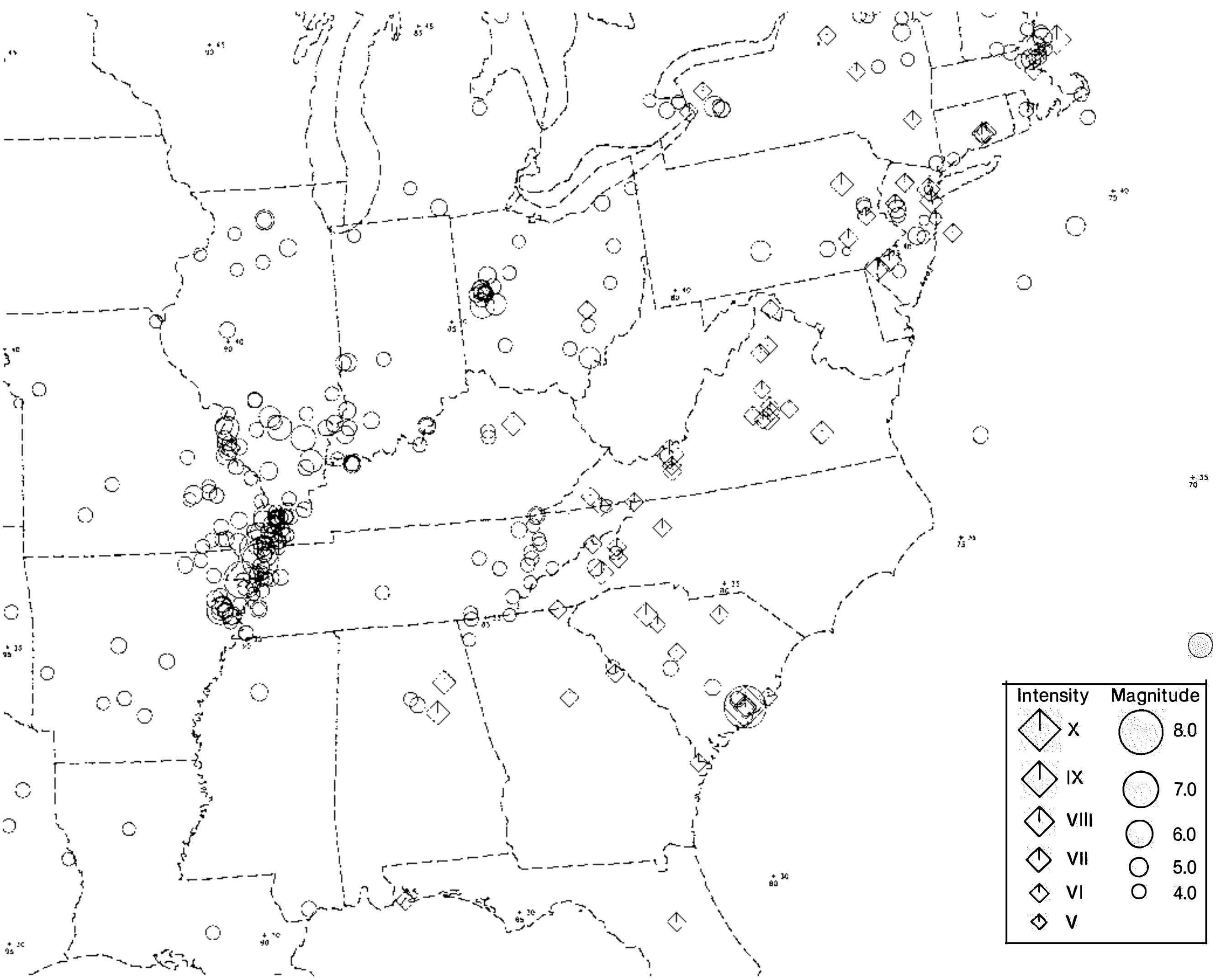
"Our understanding of earthquake processes has improved significantly in recent years, however. We know now that earthquakes occur in cycles. There is not always a continuous rate of small earthquake activity; the buildup of strain may occur at a slow rate over a very long time. So you cannot rule out the occurrence of large earthquakes in areas where there have been none in the historical record. The upshot of USGS's revised position on the Charleston earthquake is that large earthquakes can be expected anywhere favorable geologic conditions exist," Stepp adds. A major contribution of EPRI's seismic program has been the development of criteria and procedures to evaluate geologic conditions favorable for the generation of earthquakes at any location in the East.

Integrating expert judgment

One element of the utility industry's response to reassessment of nuclear plant seismic safety has been a substantial effort to develop a methodology for estimating seismic hazard that is consistent with the most current knowledge in geophysics and seismology and that explicitly quantifies the uncertainty in knowledge about the causes of earthquakes in

Eastern U.S. Seismicity

Although most people probably think exclusively of the West Coast as earthquake country, some of the largest historical earthquakes in North America have occurred east of the Rocky Mountains. Plotted on the map are earthquakes with Richter magnitudes ≥4.0 or epicentral intensities ≥5.5 (modified Mercalli scale) from the year 1534 through 1984. The map was drawn from a comprehensive earthquake data base constructed under an EPRI program to develop a basis and methodology for evaluating seismic hazards at eastern U.S. sites. Data were compiled from U.S. and Canadian government and university research records.



the East. Probabilistic risk assessment techniques, largely developed over the last 15 years for the broader task of calculating the risk of severe reactor accidents, have been adapted to this role. In essence, they yield annual probabilities that various levels of earthquake-induced ground-shaking can be exceeded at a specific site.

The seismic hazard assessment procedure requires three main types of input data: quantitative descriptions of the sources of earthquakes, including faults and other tectonic features or zones with similar geologic characteristics; estimates of the probability that earthquakes of various sizes will originate within these sources; and estimates of ground motion levels at a particular site, given a future earthquake at an assumed location within a source. The hazard assessment represents an integration of these inputs over all possible sizes and locations of future earthquakes.

EPRI has already made a significant contribution to improved seismic hazard assessment, building on methodology developed at Lawrence Livermore National Laboratory for NRC. The probabilistic risk assessment approach incorporates uncertainty and the scientific interpretations of teams of experts within state-of-the-art analyses of earthquake causes and processes. The methodology, now under review by NRC, could become the industry standard for the next generation of earthquake hazard assessments.

With funding from EPRI and a separate utility-funded Seismicity Owners Group, existing methodologies were refined and extended. The approach employed six teams of earth scientists—each team including a geologist, a geophysicist, and a seismologist—to independently interpret the available data and state the degrees of uncertainty, considering any competing hypotheses for earthquake causes and the availability of the data to evaluate them.

The interpretations were founded on a comprehensive geologic, geophysical, and seismologic data base compiled specifically for the project from National Oceanographic and Atmospheric Administration data, USGS, and such other sources as university research programs. The data base includes geologic and tectonic maps, earthquake catalogs, geophysical data, and geodetic and crustal stress information. "It is probably the most extensive data base of its kind ever amassed," notes Stepp.

During 1984 and 1985 each of the earth science teams produced tectonic interpretations for the entire eastern United States. Their evaluations were then subjected to extensive internal project review in over half a dozen workshops held around the country, as well as peer reviews by other eminent earth scientists. Results have been compared with Livermore's earlier calculations for nine reactor sites to identify differences. A report on the resultant generic methodology has been submitted to NRC. The methodology also has been encoded in a computer program (EQHAZARD) that conforms to NRC quality assurance requirements and is expected to be available in 1987.

"NRC is reviewing the seismic hazard report and will determine the methodology's acceptability for utility use in regulatory compliance—we hope by next year," comments Wall. "Beyond that, we expect to work with NRC as reactor siting regulations and seismic design criteria are revised. Having a technically supported, stable basis for determining seismic hazards could eliminate one source of licensing delay."

Gauging effects on structures

Improved methods for calculating earthquake hazards are only part of the mosaic of seismic research EPRI is pursuing for the utility industry. In the few years since its establishment, EPRI's Seismic Center finds itself at the forefront of research to advance the state of seismic engineering with key experiments to record effects when the ground becomes terra non firma.

The program has the benefit of guidance from a distinguished technical advisory panel of earthquake specialists under the chairmanship of Bruce Bolt of the University of California at Berkeley, who is also chairman of the California Seismic Safety Commission. In addition, the Institute's technical exchange agreements with utilities and research organizations in Japan, where seismic engineering for nuclear plants has long been a high priority, could become an important channel for international communication among seismic researchers.

With the help of computer modeling, for many years engineers have studied the interaction of soil and structures and the mechanics of damage. Much analysis, however, has been confined to after-the-fact examinations or small-scale simulations because earthquakes occur either too infrequently or with too little or no warning to gather detailed data as they unfold that could substantiate or verify the models. That situation is rapidly changing, in part, as a result of several major completed, current, and planned EPRI experiments.

Two series of experiments to study soil-structure interactions during strong ground motions were conducted in 1978 and 1983, using buried explosives to simulate seismic energy. Scale-model structures were instrumented to record vibration frequencies as the shock waves from the explosive detonations traveled through them.

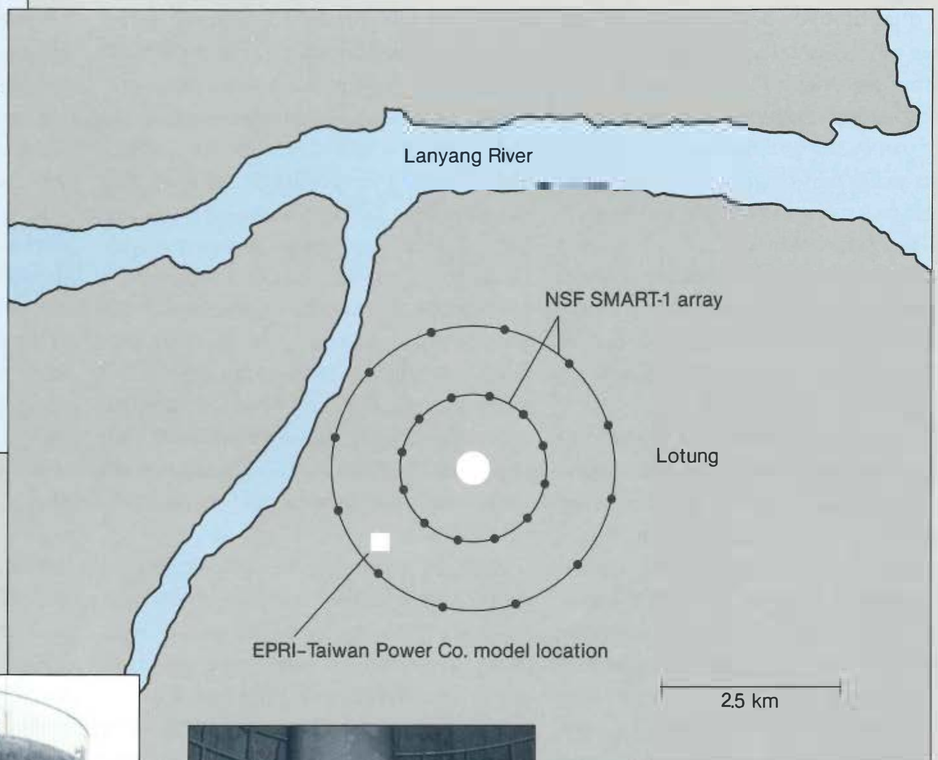
In the first SIMQUAKE series of tests, conducted by the University of New Mexico on soft soil near Albuquerque, cylindrical models of reactor containment buildings, ranging from 1/48 to 1/8 scale, were subjected to peak ground accelerations as high as 4 g, which is equivalent to 0.4 g for a 1/10-scale structure. A moderate, Richter 5, earthquake could be expected to produce ground acceleration around 0.5 g at the epicenter. Accelerations at a location away from the epicenter would depend on site conditions.

A second series, cosponsored with Niagara Mohawk Power Corp., was performed on a hard-rock site near the util-

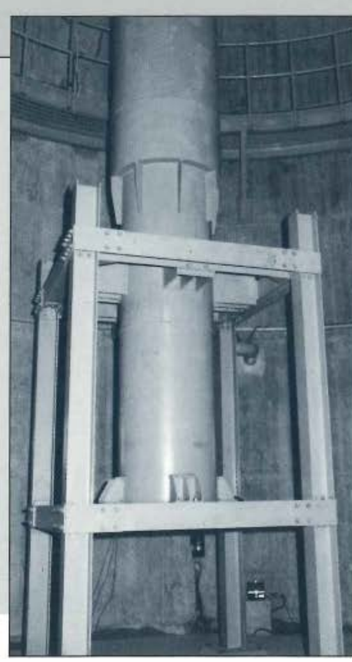
Large-Scale Soil-Structure Interaction Experiment

EPRI and Taiwan Power Co. have constructed and instrumented two scale-model PWR concrete containment buildings within an existing U.S. National Science Foundation dense seismographic array at Lotung, Taiwan, to study the interaction of soil and structures during actual earthquakes. The models, 1/4 and 1/12 actual size, are on a soft-soil site on the island, which experiences frequent, strong seismic activity.

Data from two recent temblors of Richter magnitude >6.0 were recorded by instruments buried in the ground and mounted on the structures, as well as by instruments on a mockup steam generator and pipe run inside the 1/4-scale model. Expert interpretation of the data, now under way, will help substantiate predictive models of soil-structure interaction and contribute to assessment of the dynamic response of reactor containments and components to actual earthquake-induced motion.



1/4-scale model



Steam generator mockup

Downhole strong-motion sensor

ity's Nine Mile Point nuclear plant in New York. There, four scale models (1/20, 1/10, and two 1/12 actual size) were built in backfilled rock sockets to simulate the Nine Mile Point design.

A key question addressed in the simulation tests was whether the structural response to strong ground motion is linear. Current design practice assumes it is. But comparison of results of the two test series suggests that assumption may be overly conservative for soft-soil sites. In the SIMQUAKE tests in New Mexico, the rocking frequency of the scale structures downshifted significantly from that induced by low-amplitude vibration; in the Nine Mile Point experiments on rock, the shift in rocking frequency was minor.

But simulating seismic events goes only so far in giving researchers a picture of the soil-structure interactions during real earthquakes. Explosives cannot simulate the variety of seismic waves, wave-scattering characteristics, and their effects on soil-structure interactions. To provide a more representative data base, EPRI and Taiwan Power Co. have cosponsored a large-scale experiment on the island's northeastern coast at Lotung. The project has already produced a mountain of data from one of the frequent moderate-to-strong earthquakes that rock Taiwan.

Last year, under EPRI guidance, Taiwan Power constructed and heavily instrumented 1/4-scale and 1/12-scale models of a pressurized water reactor containment building on a soft-soil site at Lotung. At the same location, the University of California at Berkeley, under the sponsorship of the U.S. National Science Foundation (NSF), has deployed a large array of strong-motion accelerometers (the SMART-1 array) to gather two-dimensional free-field seismic data as part of the National Earthquake Hazards Reduction Program. Near the containment model, 15 surface and 8 downhole strong-motion accelerographs have been deployed to specifically define the seismic environment for analysis of soil-structure interactions.

The quarter-scale model is designed to gather the maximum amount of in-structure data from actual earthquake-induced strong ground motions. Additional data are recorded inside the model by instruments on a mock-up steam generator and piping run. The 1/12-scale model will allow direct comparison of data on soil-structure interaction with the SIMQUAKE results from New Mexico and New York. NRC has sponsored low-amplitude forced-vibration tests on the Lotung models for baseline data.

Once the models and instruments were in place, researchers did not have to wait long for the next strong temblor and the data that followed. Earthquakes of magnitude 5–6 occur almost monthly on Taiwan. On January 16 of this year, a Richter 6.3 earthquake rippled through the area. "We took a lot of data from that event, perhaps more than have ever been recorded in structures or from downhole instruments during an actual quake," reports Hui-tsung Tang, an EPRI program manager who coordinated construction of the Lotung experiment with Taiwan Power.

EPRI and NRC are jointly sponsoring a major round-robin series of analyses of the January 16 data, involving seismic specialists from various universities, engineering firms, and the national laboratories. The data and subsequent analysis, expected to fill key gaps in technical understanding of soil-structure interaction, should be reported by EPRI within the next 18 months.

Because the Taiwan site has a high water table, researchers from the University of California at Davis, who are sponsored by NSF, and from EPRI will jointly conduct studies of liquefaction and soil-settling at Lotung to better understand soil stability and soil-structure interaction.

EPRI is also preparing to participate in what may be one of the most nearly ideal seismic monitoring opportunities ever in the United States for study of soil liquefaction and the spatial variability of ground motion in a known active fault zone. About 200 mi (322 km) south of San Francisco on the San Andreas Fault near Parkfield in central California, researchers from USGS, California Division of Mines and Geology, and various universities are poised with a multitude of ground motion sensors and other instruments to record the next Richter 5–6 earthquake of what has become an almost regular 22-year cycle. The last Parkfield earthquake, in June 1966, was a Richter 5.5 and produced peak ground acceleration of about 0.5 g.

By early next year EPRI hopes to have in place two major experiments near Parkfield, according to Jerry King, an EPRI seismologist and project manager. "In the first experiment, working with researchers from the USGS and Brigham Young University, we plan to have five accelerometers and six pore-pressure transducers in the ground to collect data on the buildup of water pressure in the soil during the earthquake. Data from this test will go a long way in validating or correcting predictive models of dynamic soil behavior and liquefaction," King explains.

"The second experiment will involve a dense array of seismic sensors—13 on the surface and 8 below ground—that will shed some light on the spatial variability of ground motion over an area of about 50 m (15 ft) in diameter, comparable to that of a full-scale reactor containment building," King says. "We are negotiating with USGS to combine our array with a large array they are planning to install. If we can be inside a large array, we will get a lot more data on what is coming at us." Adds Stepp, "The Parkfield experiments will give us what could be the definitive data set for strong ground motion near the source of a moderate earthquake."

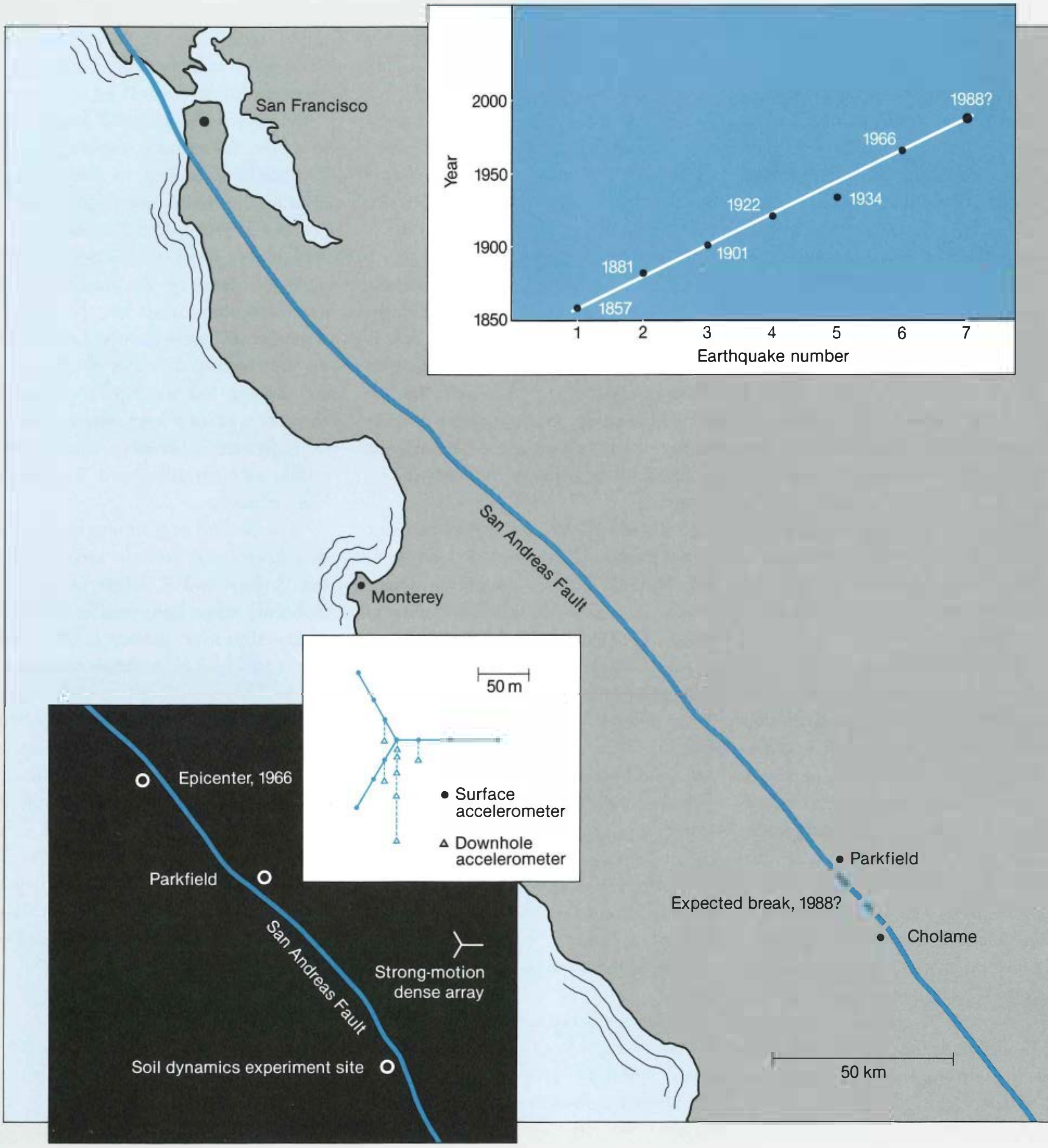
Seismic equipment qualification

Besides efforts to better understand seismic risks and the structural-mechanical effects of earthquakes, major elements of EPRI's seismic research focus on the equipment that must function in order to

Parkfield Strong-Motion Array: Waiting for the Next One

An area of the San Andreas Fault near Parkfield in central California has regularly experienced earthquakes of Richter magnitude 5–6 about every 22 years; the last one, in June 1966, was a magnitude of 5.5. Regression analysis indicates the next one is due around 1988. Researchers from USGS, EPRI, and several universities are planning two major experiments to study soil liquefaction and the spatial variability of seismic waves along the expected break between Parkfield and Cholame.

In the dense seismic array experiment, surface and downhole accelerometers will measure the coherency of earthquake ground motion over short distances and, acting like a directional antenna, will permit accurate mapping of the location of seismic energy sources. A second array will measure (for the first time) seismic motion in a saturated soil to assess the dynamics of liquefaction during an actual earthquake.



shut down a plant safely during or after an earthquake. A separate effort is addressing improved design and engineering of plant piping systems. The equipment qualification work reflects the need in the utility industry for data to support resolution of an unresolved safety issue before NRC, while the piping systems analysis focuses on one of the main areas accounting for the high cost of seismic engineering in nuclear plants.

Although the research has immediate relevance to existing plants or those nearing completion, it is also expected to help reduce the need for expensive retrofits, lower the cost, and cut the licensing time of plants built in the future. "All seismic design and related licensing requirements, not just equipment qualification, have been estimated to account for 9% of the total cost of a typical nuclear plant built in the East," notes Wall.

"For West Coast plants, which are designed to withstand much stronger earthquakes, the percentage is 15% or more. But in some recent cases, the actual total cost of seismic safety may be double because much of the engineering is done twice as a result of recurrent concerns over the adequacy of seismic safety margins as our understanding of earthquake processes has improved," adds Wall.

Many key components of a plant's nuclear steam supply system, both electrical and mechanical, must continue to function during and after a large earthquake. Although these components are designed to withstand a level of amplified shaking based on a plant's Safe-Shutdown Earthquake, the ultimate ruggedness of many of the components is not known because it is generally not the practice of equipment manufacturers to test their products to failure. There is also a large uncertainty surrounding the predictability of the size of potential earthquakes—information that is essential for a technically sound specification of a Safe-Shutdown Earthquake.

The Nuclear Power Division is sponsoring several projects in seismic equipment qualification. In many cases, qualification tests employ large shake tables on which components are subjected to high levels of excitation. "Because this approach is expensive when applied to each component, EPRI research is attempting to take advantage of the cumulative experience of over a decade of shake-table testing by the industry," explains George Sliter, project manager. "Compilation of existing data leads to a generic level of ruggedness for each class of equipment. Such an earthquake rating reduces equipment qualification costs."

In addition to EPRI-funded research on test experience data, the Seismic Qualification Utility Group has separately sponsored evaluations of actual earthquake experience data for types of equipment in nonnuclear facilities that are similar to nuclear plant systems. These studies are already leading to NRC acceptance of the seismic adequacy of some classes of installed equipment without qualification testing because their performance under actual earthquakes is known.

In a related effort, EPRI sent a team of specialists to Mexico to survey various utility and other industrial sites in and around the epicentral region of the two major earthquakes there on September 19 and 20, 1985, which were at Richter magnitudes 8.1 and 7.8, respectively. Researchers found that the earthquakes, which produced only low ground accelerations (less than 0.2 g), caused little local damage to high-voltage transmission lines or to generating stations, despite widespread damage in Mexico City.

This year the equipment qualification research team expects to complete development of generic ruggedness levels for about 25 types of nuclear plant equipment important for safe shutdown. The data will be added to a computerized equipment qualification data bank that can be remotely accessed by nuclear utilities for reference. Other projects are producing technical methods for evaluating equipment anchorages, as well as a methodology for evaluating the seismic performance of electrical system relays,

OHIO REACTOR UNDAMAGED BY TEMBLOR

Nuclear plant seismic safety made news when a Richter 5 earthquake occurred in Ohio on January 31, 1986, near the recently completed Perry-1 reactor. Epicenter of the temblor—felt as far away as Washington, D.C.—was estimated to be about 10 mi (16 km) south of the plant in northeastern Ohio. Cleveland Electric Illuminating Co. (CEI), the majority owner and operator of the plant, was awaiting an NRC low-power license to begin loading fuel into the 1205-MW boiling water reactor at the time.

Some of the in-plant ground motion sensors reportedly were tripped by the earthquake, indicating that the plant's design basis earthquake may have been exceeded. Safe-Shutdown Earthquake for the site is a 0.15-g peak ground acceleration. CEI officials said the Perry plant was designed to safely withstand a quake many times more powerful than had occurred.

NRC dispatched a team of investigators to the site, and EPRI project managers assisted the utility in analyzing data from recording instruments. A walk-through inspection revealed no signs of structural damage, with only slight damage to some nonessential items, including a small water pipe.

By March 18 NRC was satisfied that no significant damage had occurred and granted permission to begin fuel loading; the plant has since been undergoing several months of low-power tests prior to start of commercial operation. □

one class of equipment that is essential for safe shutdown.

Piping is a major class of equipment that has long been a focus of seismic safety engineering. A typical light water reactor contains about 45 mi (72 km) of pipe in various sizes, which, together with some 550 mi (885 km) of cable, are supported by up to 6000 seismically engineered hangers and snubber restraints.

Frequent retrofits and high maintenance requirements for such support hardware have led to serious congestion in some areas of plants, as well as to degraded piping reliability during normal operating cycles. Moreover, there is reportedly wide agreement in the industry, as well as within NRC, that typical piping systems have been made overly stiff and that more flexibility, requiring fewer restraints, could not only reduce costs but also increase overall safety.

EPRI has supported research on two fronts in the area of piping seismic capacity and the need for snubbers. For older plants, projects have taken a closer look at the dynamic behavior of piping and at damping capacities; for new plants, other projects have evaluated alternative energy-absorbing devices or simplified snubbers, of which fewer could be justified as necessary.

Numerous series of dynamic tests on a variety of piping components and configurations have been sponsored by EPRI in support of efforts by the Pressure Vessel Research Committee of the American Society of Mechanical Engineers to establish more-realistic pipe design criteria and stress limits. Results of some of these tests have already been reflected in ASME Code revisions.

For example, over 200 forced-vibration and transient snapback tests on a 110-ft (33.5-m), 8-in-diam (20-cm) feedwater line at Consolidated Edison Co.'s Indian Point-1 plant have led to a significant increase in the established damping values for such pipe under low-amplitude vibration. Other tests for large-amplitude dynamic response and for other classes of pipe are expected to lead to similar revisions of industry standards for seismic capacity.

NOT JUST FOR NUCLEAR PLANTS

The extensive data, methodology, and computer codes developed under EPRI's Nuclear Power Division for evaluating seismic hazard are applicable to far more than just nuclear reactor sites. The Institute's Seismic Center reports increasing interest in the use of its research results by utilities and nonutility groups for seismic analysis elsewhere.

For example, seismic source zone maps prepared with EPRI support and considered among the most comprehensive and current of any available are to be used by the Earthquake Engineering Research Institute (EERI) in developing revised hazard maps that are expected to be published as part of the national Uniform Building Code.

Current seismic maps in the code—the International Council of Building Officials' standard reference for architects and constructors—were last revised in 1969. "We are keenly aware of the contribution EPRI has made, and we plan to use those data along with USGS data," says Roger Scholl, technical director of the nonprofit EERI, based in El Cerrito, California.

Meantime, at least one large utility—the federal Tennessee Valley Authority—plans to use EPRI's EQHAZARD analytic software to study the seismic safety at many of its more than 40 hydroelectric dams in southern Appalachia. William Seay, a TVA geologist, says the utility determined the code was equally useful for other facilities, as well as for nuclear plant application. "We're conducting a systematic evaluation of all our dams in Alabama, Georgia, Kentucky, North Carolina, Tennessee, and Virginia," says Seay, "and we expect the code will help us focus our resources and review." □

Reevaluating seismic safety margins

Better understanding of the seismic hazard, of soil-structure interactions during earthquakes, and of the ruggedness of safety-related equipment will ultimately yield inputs to plant-specific evaluations of seismic safety margins.

USGS's revised position on the potential for large earthquakes in the East was the impetus for NRC's ongoing development of the seismic hazard picture in the United States. Results of an initial analysis of 10 trial sites by Lawrence Livermore National Laboratory for NRC indicate that annual probabilities of exceeding the design reference Safe-Shutdown Earthquake for those plants are in the range of one chance in 2000 (2×10^{-3}) to one in 500,000 (5×10^{-5}). For some time, NRC's staff position for probability of exceeding the Safe-Shutdown Earthquake has been 10^{-3} to 10^{-4}, although the commission's independent Advisory Committee on Reactor Safeguards (ACRS) favors an acceptable probability as low as 10^{-5}.

Comparable calculations from EPRI's seismic hazard assessment indicate probabilities lower than the Livermore results by an order of magnitude for the same ground motion values, according to Stepp. The results have been studied to determine the sources of difference. In general, the differences are attributed to the choice of seismic energy attenuation relationships—an area where continuing R&D is expected to bring closer agreement—and to varying assigned source zone geometries, reflecting scientific uncertainty regarding the causes of earthquakes.

"Depending on the results of NRC's seismic hazard review, in the near future several utilities may be required to demonstrate that their nuclear plants have adequate margins to safely withstand earthquakes larger than their design Safe-Shutdown Earthquake," explains Ian Wall. "All plants east of the Rockies are subject to the possibility of an NRC directive to reevaluate seismic safety margins."

But as Wall and other EPRI research managers point out, the industry lacks an accepted methodology and detailed guidelines for evaluating seismic margins. EPRI is now developing such a methodology, which will be submitted for approval by NRC and ACRS for use by utilities by the time the seismic hazard reassessment is completed and some plant safety margins must be reconsidered. The two main elements of the development effort are a screening procedure to limit the scope of analysis to those systems and components necessary for safe shutdown and analytic methods for detailed evaluations of those systems and components.

Robert Kassawara, subprogram manager for seismic margin methodology development, explains that the goal is a generic procedure that nuclear utilities with varying engineering capabilities can use to guide a systematic screening and evaluation at individual plants. "The ultimate objective of the methodology will not be to calculate the margin of safety at a specific plant; rather, it will be a procedure for plant review to determine whether it can shut down safely under an earthquake larger than the Safe-Shutdown Earthquake. The earthquake size will be specified from a seismic hazard assessment. The methodology will permit a utility to show with a high degree of confidence that the equipment needed to shut down the plant can withstand higher motion levels."

The research on seismic safety margins will draw on and integrate many of the data being gathered and generated from other elements of seismic research performed by EPRI, NRC, and utility owners groups, including revised hazard estimates, earthquake experience and testing of equipment, and safety margin assessments sponsored by NRC.

Kassawara reports that methodology development is well under way, focusing initially on a typical pressurized water reactor, with similar study of a boiling water reactor to follow. The margins review guide that will result could be available early next year. NRC and EPRI have agreed to share their respective reevaluation procedures by applying them to two plant case studies and comparing results.

One area of regulatory uncertainty that could become an additional focus of industry-supported R&D involves the restart of a reactor following an earthquake that exceeds the plant's design operating basis earthquake. The NRC's regulations specify that a plant must immediately shut down in that event—which has yet to occur for any operating reactor in the United States. But there are no detailed criteria in place to determine the seriousness of the event or what must be done to permit restart. EPRI-funded development of such a postearthquake inspection procedure could be a logical follow-on to the plant seismic margins review.

Seismic risk: a reappraisal

The probability of large earthquakes figures significantly in the comprehensive, severe-accident risk assessments that have been performed for many nuclear plants in the United States. Despite the reassessment of eastern seismic hazard that is in progress, important research sponsored by EPRI and other institutions around the country is chipping away at the uncertainty bounds of that risk, providing a clearer picture of its nature and implications for reactor safety.

As more becomes known about seismic risk and nuclear plants, the greater the confidence should be among regulators and utilities that plants have substantial margins of safety designed and built into them to withstand strong earthquakes. R&D to quantify those margins may have far-reaching effects, not only in reducing the cost of seismic safety for existing and future reactors but also in determining the public's perception of risk and safety.

"There are and will continue to be additional costs to the utility industry in the near term with this seismic margin issue," notes Wall. But as Walter Loewenstein, director of EPRI's Safety Technology Department, adds, "In the long run, the research programs being carried out by utilities, EPRI, and NRC should demonstrate the seismic ruggedness of nuclear power plants and hence provide additional assurance of reactor safety to the public. Further, a more technically sound basis for seismic design will help stabilize the licensing process insofar as seismic safety is concerned and should help shorten the design and construction periods for the next generation of nuclear plants." ■

Further reading

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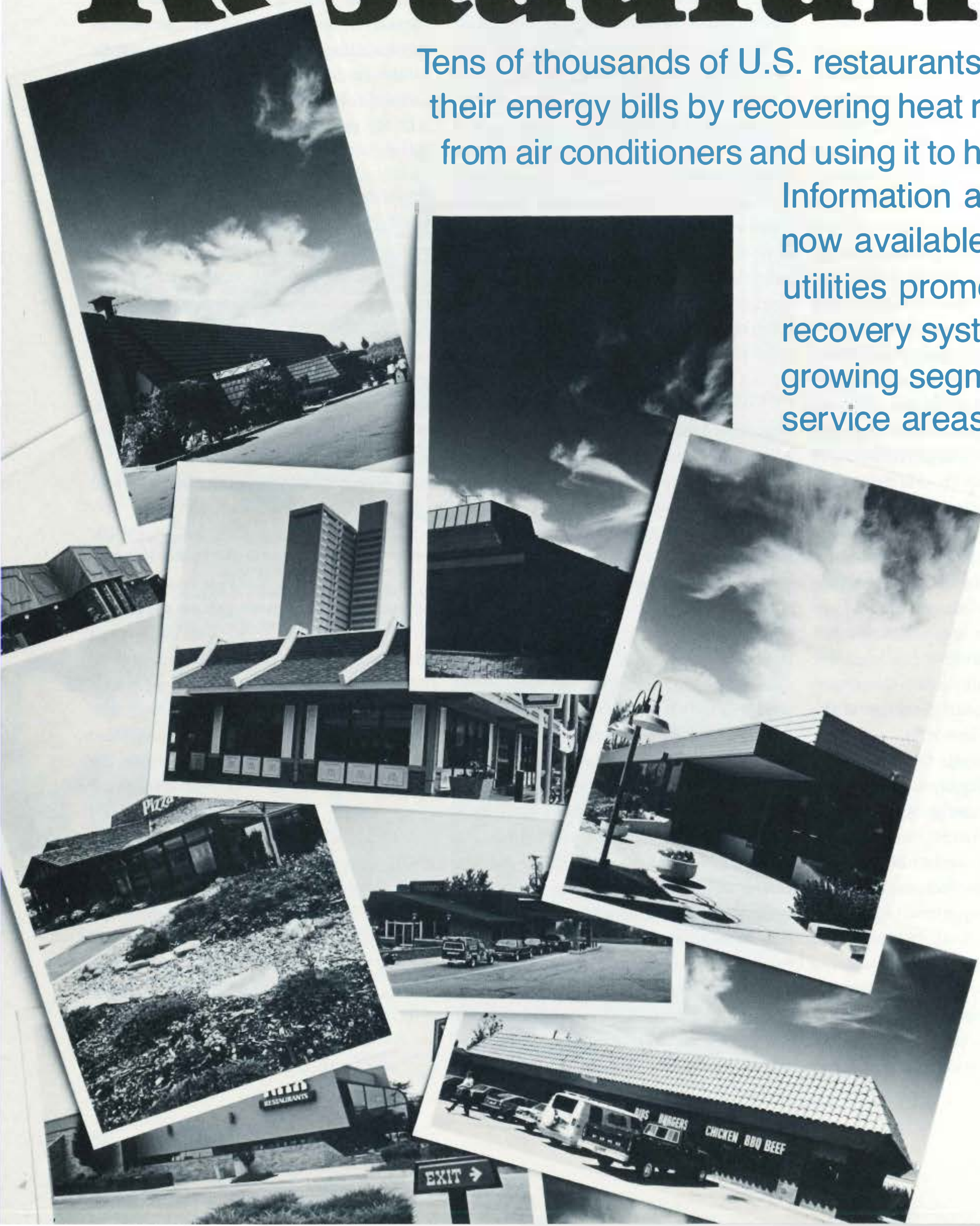
This article was written by Taylor Moore. Technical background information was provided by Robert Kassawara, Jerry King, J. Carl Stepp, Hui-tsung Tang, and Ian Wall, Nuclear Power Division. Additional background information was provided by George Sliter and Yu-kuang Tang, Nuclear Power Division.

Heat Recovery for Restaurants

Tens of thousands of U.S. restaurants could lower their energy bills by recovering heat rejected from air conditioners and using it to heat water. Information and tools are now available to help utilities promote heat recovery systems for this growing segment of their service areas.



Consider the electricity requirements of a small fried chicken restaurant in Miami, Florida, on a sweltering day in July. The air conditioning system must be run at its highest setting for the comfort of both the customers and the kitchen personnel. In the kitchen, where electric-powered fryers and ovens add to the natural heat, approximately 200 gallons of water are electrically heated for the day's cooking and cleaning. Other sources of demand include the indoor and outdoor lighting, a refrigerator, a freezer, and appliances for processing food. By closing time at 10 p.m., the day's electric consumption will total more than 700 kWh. The July electric bill for this 1000-ft^2 (93-m^2) establishment: more than $1500.

EPRI research confirmed that tens of thousands of fast-food and full-service restaurants, including the one above, can benefit by installing heat recovery systems on their air conditioning compressors. Commercially available since the early 1970s, these systems recover exhaust heat from compressors and use it to heat water. In the restaurant industry, where large demands for air conditioning and water heating often coincide, the systems can provide fast paybacks through cost saving for energy.

In the restaurant described above, for example, air conditioning is needed virtually every day of the year. Thus, the air conditioning system is steadily supplying enough exhaust heat to meet the daily hot water needs. Over the course of the year, the heat recovery system will replace a water-heating demand that averages 35 kWh/d, about 5–6% of the total electricity used. In dollar figures, this means that an owner paying $0.075/kWh will save about $1000 a year. An easily installed heat recovery system, consisting of a heat exchanger, conventional pump and piping, and a water storage tank, should pay for itself within one to three years.

In spite of these opportunities for energy and cost savings, most restaurants have not taken advantage of the system. EPRI studies suggest that although many national restaurant chains have specified heat recovery systems for franchise operations, the majority of restaurant operators do not even know that such systems exist. At the same time, an even larger majority are without technical information needed to gauge the benefits of the systems at different sites or to effectively choose and install the systems. Consulting firms are available to fill these needs, but their fees are often too steep for the owners of small businesses.

"The shortage of technical knowledge among restaurant owners is the largest obstacle to implementation of the systems," explains I. Leslie Harry, EPRI project manager in the Energy Management and Utilization Division. "And the high price of technical information is the main reason for that lack. Utilities can now enter the picture and play an important role in making information about the systems available to their restaurant customers."

A promotional role for utilities

To electric utilities the restaurant market for heat recovery systems offers unique opportunities to promote conservation, reduce demand peaks, and support the electrification of a large and undeveloped area of the commercial sector. Compared with other businesses, the some 200,000 restaurants in the United States use huge amounts of electricity, accounting for approximately 75×10^9 kWh (approximately 14% of all commercial sector electrical energy use). As substitutes for electric water heaters, heat recovery systems can produce peak demand reductions of 5–10% in thousands of restaurants. At the same time, replacing gas water heating with compressor waste heating (and, if necessary, supplemental electric resistance heating) can provide some utilities with an opportunity to build load in their service areas.

On the national level, utilities have just begun to explore these various opportunities. In spite of an increase in utility conservation, load management, and general marketing programs aimed at commercial sector customers, an estimated two-thirds of U.S. restaurant operators do not contact utility representatives in the course of a year. At the same time, American Gas Association studies show restaurant energy bills rising steadily as a percentage of operating costs since 1974. Correspondingly, the same studies show an increased interest among restaurant owners in implementing conservation techniques.

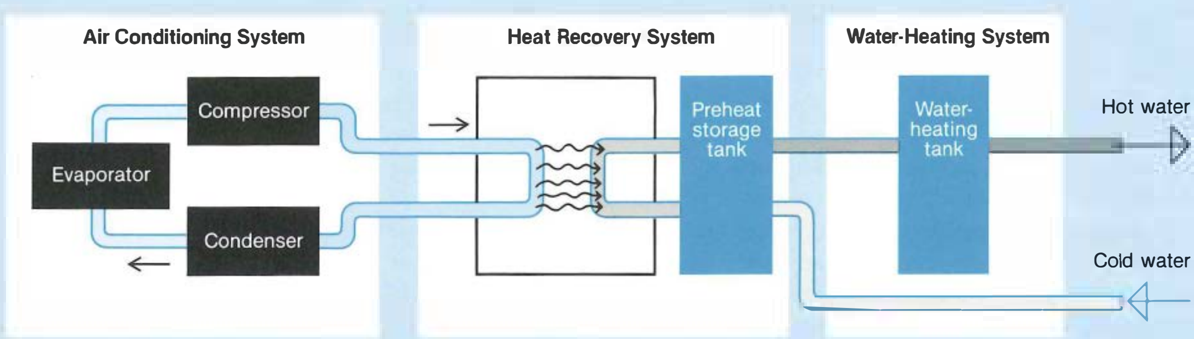
"Restaurant applications of heat recovery systems have a large, unrealized potential as a means of promoting the efficient use of electricity," states Harvey Bierenbaum, president of Applied Energy Systems, Cocoa Beach, Florida, a firm that investigated the systems and the restaurant industry for EPRI. "The market is still wide open for the systems in thousands of restaurants, where they can be used as starting points for promoting utility incentive programs, and electric appliances. Restaurants are also a fast-growing segment of the commercial sector, with 10,000 more food service establishments in business each year."

The opportunity the systems offer to utilities is further enhanced by the simplicity and uniformity of restaurant applications. Most restaurants have relatively simple air conditioning and water-heating systems that make it easy to plan and implement heat recovery installations. As opposed to the multiple compressors and water-heating tanks found in many other commercial and industrial facilities, most smaller restaurants rely on one or two air conditioning compressors and a single water-heating tank. In addition, the compressors in restaurants are often located within a short distance of the water-heating tank, making it relatively easy to link the two components with a heat recovery system. Also, the compressors in restaurants are nearly all of the reciprocating type, the design proved most effective for heat recovery.

"The promotion of these systems is well within the capabilities of most utility customer service or marketing pro-

Using Waste Heat

The basic component in the heat recovery system is a heat exchanger located just downstream from the air conditioner compressor. Waste heat, liberated as the air conditioner coolant is compressed, is transferred by the heat exchanger to a supply of cold water; the heated water can then be used for dishwashing, cleaning, and other restaurant chores. After the heat transfer, the air conditioner's refrigerant vapor continues through the loop to a condenser, where it is retured to liquid form.



Type of Food Typically Served	Restaurant Chain	Number of Facilities
Family	Steak'n Egg	400
Family	Waffle House	460
Family	Denny's	1805
Family	Seasons	1117
Family	Shoney's	642
Family	Frisch's	244
Ice cream/Hamburgers	Steak'n Shake	101
Ice cream/Hamburgers	Friendly Ice Cream Corp.	641
Steak/Grilled entrees	Sizzler	451
Steak/Grilled entrees	Quincy's	110
Steak	Mr. Steak, Inc.	277
Steak	Ponderosa	681
Steak	Western Sizzlin	475
Steak	Bonanza	680

Finding the Market

In the southern United States, where restaurants typically require heavy, year-round air conditioning, most full-service restaurants make excellent candidates for compressor heat recovery systems. The size of this market is suggested by one subgroup of about 8000 good candidates: major, full-service chain operations in the South. Studies show a high interest in energy conservation among restaurant owners, but heat recovery systems are among the cost-effective technologies that are least understood and least applied.

grams," Harry explains. "In fact, the relative simplicity and uniformity of these applications lend themselves to the development of generic tools and materials that utilities can use to promote the systems to restaurants in their service areas."

Systems in operation

The vast majority of both fast-food and full-service restaurants use a simple compression cycle to cool their kitchens and service areas. The cycle circulates a liquid refrigerant (usually a variant of Freon) through an evaporator. As the refrigerant evaporates, it picks up heat from the air. It next flows to a compressor where it is squeezed into a high-pressure, high-temperature vapor. This superheated vapor then moves to a condenser where it loses heat and returns to liquid form for recycling. It is the heat ordinarily lost to the surrounding air in the condenser that is captured and used by a heat recovery system.

The primary component of a compressor heat recovery system is a heat exchanger (one for each compressor) that is installed in the hot-vapor discharge line just downstream of the compressor. Depending on their air conditioning systems and requirements, some restaurants will benefit most from heat exchangers on both their kitchen and dining area compressors. Others have only one compressor, or they install heat exchangers only on those compressors they use most. Each heat exchanger is linked to a compressor and to the restaurant's water-heating supply and existing water-heating tank. A supply of cold or moderately heated water is piped through the heat exchanger, where it picks up heat. Electrical heating can then be used, if necessary, to supplement or boost available compressor heat.

In addition to the heat exchanger, the remaining components of a heat recovery system consist of common water piping components (pipes, valves, and circulating pumps) and, in most cases, an additional water preheat storage tank. The preheat storage tank is used to control the supply of cold or moderate-temperature water to the heat exchanger (rather than hot water from the existing water-heating tank). This capacity for storing water at moderate temperatures keeps the heat recovery system operating more efficiently. Water is not overheated, and heat from the compressor is not wasted when the demand for hot water lets up.

Besides heating water, the desuperheating of the gases leaving the compressor has a positive effect on the efficiency of the compressor. With the heat recovery system in place, the air conditioning system becomes slightly more efficient in removing heat from the surrounding air. Refrigerant vapor is condensed at a slightly lower temperature, and the compressor gains in energy efficiency by approximately 3%. Although this improvement in energy efficiency seems insignificant, it results in a small reduction in peak electricity demand. In larger restaurants, these efficiency improvements can translate to cost savings of hundreds of dollars a year.

Gauging cost-effectiveness

Basically, the cost-effectiveness of the systems depends on the kind of water heating that is being replaced and on the combined air conditioning and water-heating requirements of a given restaurant.

Typically, a restaurant will be required by law to clean dishes, utensils, and cooking facilities with water at temperatures in the range of 140–180°F (60–82°C). This creates a large hot water requirement, ranging from 200 gal/d in a typical, small fast-food restaurant to thousands of gallons a day in a large full-service restaurant that must wash dishes, glasses, and utensils. It follows that these full-service restaurants use the most energy for water heating and have the largest potential for energy and cost savings.

Air conditioning use, however, will vary at different restaurants in different climates. A typical fast-food restaurant in southern Florida, for example, will use two to three times more energy for air conditioning each year than will an identical facility in New York City. Because the energy recovered for water heating is directly related to use of the air conditioning system, restaurants with high and year-round air conditioning loads (such as those in the southern United States) are the most obvious candidates for heat recovery systems. If the systems are used to replace electric water heaters, they can pay for themselves within two to four years in the large majority of fast-food and full-service restaurants in the southern United States. In southern full-service restaurants, where the water-heating requirements are greatest, the paybacks are likely to be quicker.

Research shows that these payback periods will generally become less attractive as one moves farther north and less air conditioning is needed. However, many large full-service northern restaurants combine large hot water requirements with high air conditioning loads that begin in spring and extend into fall. In this category of northern restaurants and even in some larger fast-food restaurants in the North, the systems can make cost-effective alternatives to electric water heating.

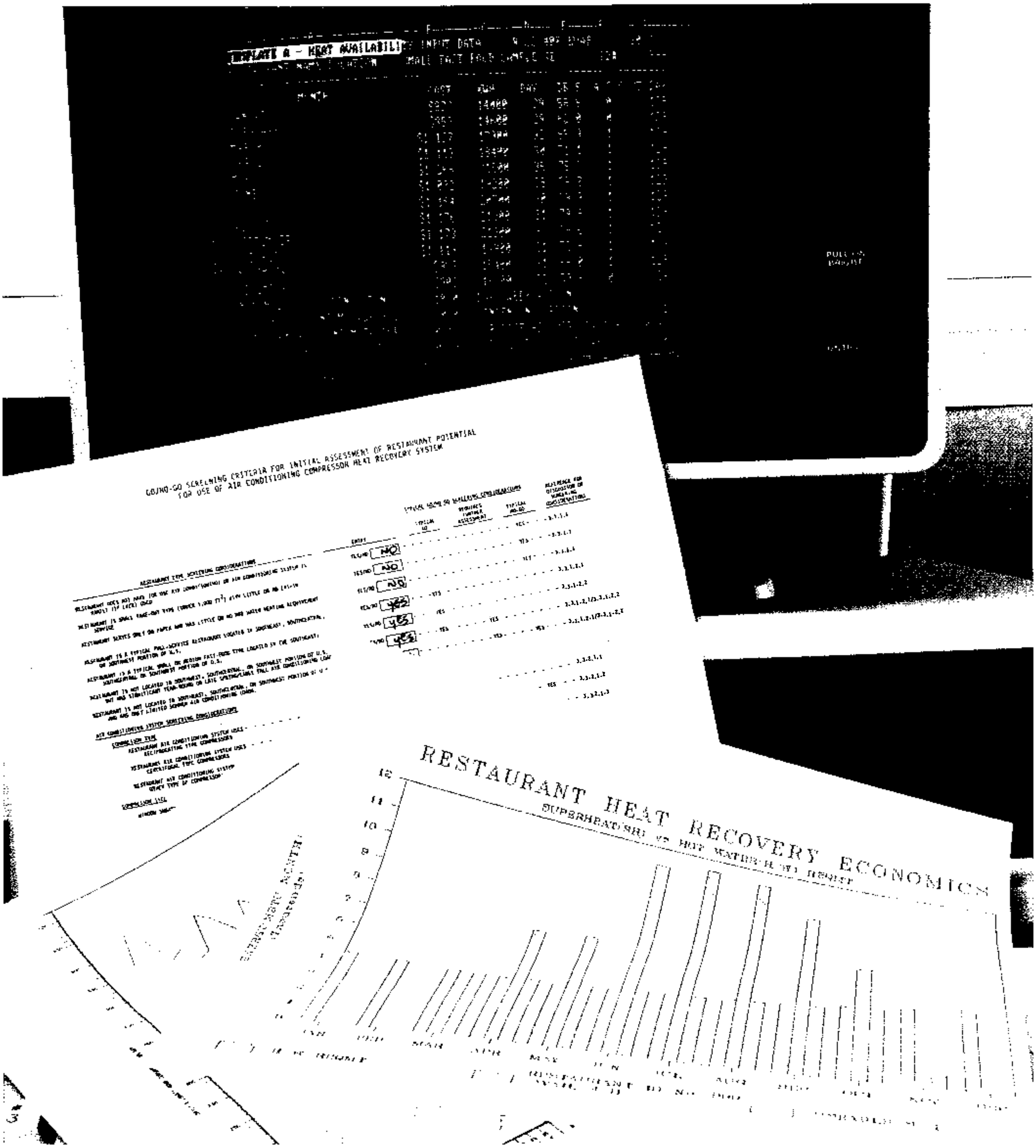
As replacements for gas water heaters, the systems prove most cost-effective and cost-competitive in full-service restaurants with very heavy water-heating and year-round air conditioning loads, such as most full-service restaurants in the southern United States. In addition, only restaurants in this category are likely to see economic benefits from the systems in areas where electricity is available at very low rates. In all cases, the prevailing cost of energy will have a large influence on the economic benefits that compressor heat recovery systems can provide.

Developing tools for utilities

EPRI sponsored a series of studies that helped to bring the benefits of promoting the systems into focus for electric utili-

Working With the Software

Running on personal computers, the restaurant heat recovery economic analysis template package offers graphics presentations and a summary of results that are easy to read and understand. Inputs specific to each restaurant are taken from utility billing data and a short survey of the dimensions and requirements of each site. Utility personnel can then quickly calculate the cost of implementing heat recovery systems, the payback period, and the energy and cost savings that the systems can provide.



ties. These studies ranged over utility goals and needs; patterns of end-use in the restaurant industry; and all aspects of designing, installing, and using the systems. Following a 1980 survey of representative member utilities, EPRI began an effort to incorporate this wide range of technical and marketing information into tools and materials that utilities can use to promote the systems to restaurants.

The development and evaluation of the restaurant tools were completed in mid 1986. The tools include the *Restaurant Heat Recovery Handbook*, which is the first comprehensive information source on the subject. Screening materials are provided in the handbook in a go/no-go format that allows utility personnel to quickly sort out those restaurants where the systems can prove cost-effective. The handbook also contains more-detailed assessment materials, including worksheet formats for calculating the costs and benefits of system installations at specific restaurants. In addition, it offers detailed technical information on current system alternatives, including guidelines for designing and implementing the systems.

Following initial field trials of the handbook, utility personnel asked for computerization of the time-consuming screening and assessment processes that the handbook describes. In response, EPRI developed a computerized assessment package that uses utility billing data and site-specific inputs to predict the energy and cost savings that heat recovery systems can provide at different restaurant sites. The software—the restaurant heat recovery economic analysis template package—can also be used to estimate the payback periods and the costs of implementing the systems. It is designed for compatibility with the popular Lotus 1-2-3 spreadsheet program and runs on the IBM PC and compatible microcomputers.

The software and its accompanying user manual have been tested and refined in a rigorous utility verification program that was completed in 1984. More recently, the package has been used by several utility marketing departments. For example, San Diego Gas & Electric Co. used the software to confirm the results of its own efforts to identify potential system users among the some 1300 restaurants in its service territory. Comparing results from the software package with data gathered at restaurants with heat recovery systems in place, SDG&E found close agreement (within 5%) between predicted and actual energy savings. To date, the utility response to the software has been unanimously positive with regard to its accuracy and ease of use.

Expanding applications

In addition to restaurants, compressor heat recovery systems have proved cost-effective in several other commercial establishments, including hospitals, office buildings with unusual hot water requirements (such as those that contain spas or gyms), and institutional food service facilities. Although these applications tend to be more complex than restaurant systems, they might be promoted in the future with slightly modified versions of EPRI's restaurant package.

"The tools and materials we have developed for restaurant applications can be viewed as building blocks," states Harry. "EPRI could conceivably develop these tools for more-complex commercial or industrial applications, or the development work could be done by individual utilities."

Development and use of the tools, as Harry explains, will vary among utilities with different needs and goals. "Some utilities may use these tools with an emphasis on conservation; others will focus on reducing demand peaks or on building load. The systems can help utilities in different ways, but every installation will result in a more efficient use of electricity and, in thousands of restaurants, a better bottom line for the owner." ■

Further reading

Assessment of Restaurant Heat Recovery and Load Leveling. Final report for RP1087-3 (4 vols.), prepared by Applied Energy Systems, Inc., March 1986. EPRI EM-4461.

Floating Pressure Set Point Controls for Energy Savings and Peak Demand Reductions in Industrial and Commercial Compressor Systems. Final report for RP2224-1, prepared by Applied Energy Systems, Inc., July 1985. EPRI EM-4126.

Load Leveling on Industrial Refrigeration Systems. Final report for RP1088, prepared by Applied Energy Systems, Inc., January 1982. EPRI EM-2208.

Assessment of the Potential for Heat Recovery and Load Leveling on Refrigeration Systems. Final report for RP1097 (2 vols.), prepared by Arthur D. Little, Inc., March 1980. EPRI EM-1348.

This article was written by Jon Cohen, science writer. Technical background information was provided by I. Leslie Harry, Energy Management and Utilization Division. Additional support was provided by David Hu and Gary Purcell.

TECHNOLOGY
TRANSFER
NEWS

Group Technology Transfer Wisconsin Style

Four utilities in eastern Wisconsin have found a direct and very effective process for technology transfer—the utility group invites an EPRI technical division to make a presentation based on an agenda composed of items of special interest to them. The success of this approach depends on several factors: forming a group of utilities with similar interests and located within a compact geographic area, receiving strong support from senior utility management, composing an agenda that is based on genuine utility needs, and inviting utility staff members who can realize the most benefit from the presentation.

The utilities in eastern Wisconsin—Wisconsin Electric Power Co., Madison Gas and Electric Co., Wisconsin Power and Light Co., and Wisconsin Public Service Corp.—have formed the Wisconsin Upper Michigan Systems (WUMS) R&D committee. Focusing on applicable research products from individual EPRI technical divisions, the WUMS group develops an agenda based on recommendations from utility staff members who serve on EPRI task force committees. The agenda consists of EPRI projects that are ready for utility application and of particular interest to the WUMS members.

The first presentation, given by the EPRI Coal Combustion Systems Division in July 1985, was a resounding success. Members of the WUMS committee invited utility personnel who were interested in fossil fuel plant technologies; the 52 attendees represented every fossil plant in the WUMS group and included plant managers, operating superintendents, and staff engineers from all four utilities.

The success of the July meeting inspired the WUMS members to schedule two days for the October 1985 presentation by the Energy Analysis and Environment Division. Because of their interest in end-use technologies, staff members of the Wisconsin Public Service Commission were invited to attend the third day of the June 1986 meeting, which focused on applicable research from the Energy Management and Utilization Division.

Endorsement by senior management is an essential factor in successful technology transfer. The WUMS committee realizes the key role that its senior management has played in the success of this program and has made it a policy to invite at least one senior officer to attend these presentations. Sol Burstein, the vice chairman of the Board of Directors of Wisconsin Electric Power Co., attended the EAE presentation; Donald J. Helfrecht, chairman, president, and CEO of Madison Gas and Electric Co., participated in the most recent EMU review. The WUMS group hopes to continue this tradition of having a senior officer of one of the member utilities present at each of the future presentations.

Technology transfer does not end with these meetings. The attendees are contacted in connection with each utility's ongoing benefits assessment, and WUMS members arrange for each attendee to review product books from relevant EPRI technical divisions. The four utilities use this process to discover research products that may benefit them, demonstrations in which they may wish to participate, and research topics that the utilities may want to explore.

Can this approach work for utilities located in other parts of the country? Robert Bischke, the technical information coordinator for Wisconsin Electric Power Co., thinks so, provided that the utilities in a group share common interests and are close enough to drive to the presentations. In eastern Wisconsin all four utilities have a generation mix composed of approximately 60% coal plants and 30% nuclear plants, and it is easy to draw up an agenda that reflects shared interests.

This creative method of group technology transfer has resulted in additional benefits for these utilities and their staff members: a sustained audience interest because the material presented is of special interest to them, an opportunity for attendees to share ideas with their peers and get to know one another, and a closer working relationship between the utilities in the group. ■

Issues Management Tools for Planning

Utilities are increasingly drawing on the field of issues management to help steer a steady course in the face of emerging public issues. This new approach combines futures research, environmental scanning, and long-range planning to address issues early, constructively, and positively.

To learn more about this developing field and its applications, utilities can turn to a new EPRI report, *Issues Identification and Management: The State of the Art of Methods and Techniques* (EPRI P-4143). This utility resource includes an inventory of roughly 25 issues management tools, including surveys, structured interviews, scanning, content analysis, decision support systems, and various computer-assisted approaches. The report goes further to evaluate the methods and techniques based on cost, required expertise, startup time, ease of understanding and implementation by management, computer and data base requirements, and general usefulness to utilities. In addition, the report outlines a prototypical approach to establishing an issues management capability and identifies information sources. ■ *EPRI Contact: J. Sherman Feher (415) 855-2838*

Reference Guide Targets Electrotechnologies

Recent growth in the industrial use of electricity has opened a door for utilities seeking to help their industrial customers make the most of new electric power technologies (electrotechnologies). By working closely with their industrial customers to implement these technologies, electric utilities can manage loads more effectively, market new service and power options, develop a competitive advantage over alternative energy sources, and help stimulate local economies.

In keeping with these objectives, the *Electrotechnology Reference Guide* (EPRI EM-4527) can help utility personnel evaluate the electrotechnology application requirements of their industrial customers. The guide offers concise analyses that are divided into three sections: the industrial sector and its elements; the electrotechnologies and their potential load impact; and target opportunities and applications for electricity substitution. The industrial sector is categorized into four groups—process industries, metals production, metals fabrication, and nonmetals fabrication. For each of these industry categories, the guide offers estimates of electricity consumption by different electrotechnologies in 1980, as well as projections for 1990 and 2000. Among the electrotechnologies analyzed are induction heating and melting, plasma processing, industrial heat pumps, laser processing, and adjustable-speed ac motor drives. ■ *EPRI Contact: I. Leslie Harry (415) 855-2558*

Modular Modeling Saves Money

Engineers and planners with little modeling expertise can now make use of an efficient, economical, and user-friendly computer code to simulate the dynamic performance of fossil fuel and nuclear power plants. The modular modeling system (MMS) facilitates plant availability improvement, efficiency upgrades, and plant cycling studies. The system can also aid posttrip evaluations, operational strategy development, controls analyses, training simulator qualifications, and accident analyses.

MMS contains more than 100 modules that represent all major components used in conventional fossil fuel, pressurized water, and boiling water reactor power plants, including balance-of-plant components and control elements. All modules are self-contained and can be interconnected in various arrangements to represent the desired power plant systems configuration. The user simply inserts parameters into the preengineered modules to represent specific plant components.

MMS has been successfully validated for accuracy, predicting transients recorded in both fossil fuel and nuclear power plants. To date 15 organizations, including 12 utilities, have joined the User Group organized by the EPRI licensee, Babcock & Wilcox Co., and are actively using MMS. Boston Edison Co. estimates a first-year fuel cost saving of at least $1,380,500 from implementing control improvements identified through MMS use at its Mystic-7 plant. Duke Power Co. estimates a minimum saving of $100,000 a year per plant by using MMS to avoid various power plant disruptions. EPRI Licensee: Babcock & Wilcox Co., P.O. Box 10935, Lynchburg, Virginia 24506-0935. ■ *EPRI Contact: Murthy Divakaruni (415) 855-2409*

UTILITIES: If you have been involved in an interesting use or adaptation of EPRI research products, we would like to know about it. Please send a brief description of the work with your name and telephone number to Kathy Kaufman, EPRI, P.O. Box 10412, Palo Alto, California 94303.

R&D Status Report
ADVANCED POWER SYSTEMS DIVISION

Dwain Spencer, Vice President

AVAILABILITY IMPROVEMENT ANALYSIS

The design of a new electric power generating unit is typically controlled to some extent by its costs. A unit's final design is not likely to be one with the highest possible availability, and many options for improving availability, each at its own cost, remain possible. Design analyses of the Cool Water demonstration unit (the first commercial-scale coal gasification–combined-cycle unit) revealed several options for improving availability. The costs of some of these options were less than the value of the benefits, and they were implemented. Other options were not economically viable and were not implemented. This kind of benefit/cost analysis of availability improvement is germane to every new design and program to upgrade existing operating units. Such analysis is often difficult, however, because a program may have options that interact with one another and may not be linear with regard to benefits or costs. There may also be constraints on capital, schedule, or manpower, which may determine the candidate selection. Selecting the best set of options from a group of candidates can be exhaustive or even unfeasible if the candidate group is large. This status report describes a methodology developed to facilitate the selection process, as well as its first application to a test case.

Methodology

The purpose of this availability optimization methodology is to minimize the cost of electricity by selecting the most economically beneficial availability improvements. Typically, there are many ways to improve the availability of a unit or a subsystem, which include adding more-reliable equipment, increasing redundancy, and reducing downtime for maintenance. This methodology addresses any or all of these when the costs and effects can be quantified. Even if quantification is difficult or only approximate, useful insights can be obtained. Some of these options may interact, leading to nonlinear rather than additive results, and this special need is met in the final part of the process.

A typical problem starts with a list of candidate improvement options for either a new design or an existing plant. There may be a capital constraint that dictates an upper limit and ensures that not all the options will be implemented, or there may be a value constraint that limits the selection to those meeting a specific return on investment. If the options do not interact and if each contributes to the other in an additive sense, the path to a solution is straightforward. Using some availability evaluation method, it is possible to assign a benefit to each option. These two elements—the benefit and the option cost—facilitate the selection of options that meet the appropriate financial criteria.

If the proposed options are not simply additive, the problem becomes much more complex. It then becomes necessary to consider all possible combinations of options and evaluate each as if it were a single entity to be compared with each of the other combinations. This approach may not be feasible because a relatively small number of candidates can result in a huge number of combinations.

The UNIRAM availability assessment methodology, developed under EPRI contract, is one method for determining how a change in equipment or other unit characteristics affects availability. It is the basis for the optimization approach discussed in this report, which addresses the problem for complex combinations by a multistep process that reduces and orders the combinations for easy selection. The elements of the procedure include the following.

- ▫ A UNIRAM (availability) model of the unit being evaluated and data for establishing a baseline measure
- ▫ A list of components or other options to be evaluated, which must include the mean time between failures (MTBF), the mean downtime (MDT), and the capital cost of each
- ▫ A cost model for the unit, which describes the relationship between availability changes and expenses (e.g., replacement power, fuel)
- ▫ Other constraints (e.g., capital improvement budget)

In the first of the three-step procedure, an analyst uses the availability model to evaluate the effect of each individual component change and selects from the options list those that will meet minimal criteria. If the options exceed the constraints, the analyst uses the second step, an integer programming algorithm, to obtain the set of components that meet capital constraints and optimize the cost benefits considered only as the simple sum of the option. If the options do not exceed the constraints, the analyst can omit step 2 and apply step 3. The third step uses a dynamic programming algorithm to examine the relationship between options that have passed steps 1 and 2. The analyst derives the final optimal set from this third step, together with information on optimal sequencing if all options are not implemented simultaneously.

Application results

Validation of the method requires its application to real cases and a comparison between the results obtained with it and those obtained in other ways. EPRI plans to apply the method to two or three cases. The first of these, the one with Potomac Electric Power Co., has been completed. This problem dealt with a planned 10-year life extension analysis of three currently operating units constrained by specific annual capital budgets.

In the first year, the utility considered 16 component improvement options on two units, 9 on unit B, and 7 on unit C. Step 1 reduced these 16 options to 4 on unit B and 2 on unit C. As the total cost for the 6 options did not ex-

Table 1
AVAILABILITY IMPROVEMENT ANALYSIS RESULTS
(calendar year 1987)

Unit A Candidates	Proposed Implementation	Step 1 Assess Individual Value (UNIRAM)	Step 2 Determine Combined Linear Cost Value	Step 3 Evaluate Interactive Value and Scheduling
Rewind generator stator	1993	Dropped		
Partially rewind field	1993	Acceptable	Defer	
Replace high-pressure–intermediate-pressure inner shell	1993	Acceptable	Acceptable	Acceptable, 1987
Replace high-temperature reheater	1987	Acceptable	Acceptable	Acceptable, 1987
Replace high-temperature superheater	1993	Acceptable	Defer	
Replace drive controls on induced draft fan	Open*	Dropped		
Modify or replace boiler feed pumps	Open*	Dropped		
Replace one condensate booster pump	Open*	Dropped		
Replace two condensate booster pumps	Open*	Dropped		
Improve condenser partials	Open*	Dropped		
Add redundant pulverizer	Open*	Dropped		
Replace coal feeders	Open*	Acceptable	Defer	
Replace exhauster bearing	Open*	Acceptable	Acceptable	Acceptable, 1987

*Low-cost priority candidates; no designated funding.

ceed the capital allocated, the analysis then proceeded directly to step 3. This step eliminated an additional option, ending with three changes on unit B, with a total benefit/cost ratio of 1.55, and two changes on unit C, with a benefit/cost ratio of 2.34. These options have been recommended as the most desirable for implementation.

For the second calendar year being analyzed, units A and C were considered for a combined total of 25 potential improvements. The first step reduced this number to 9; however, these exceeded the capital constraint. Application of step 2 resulted in a total of 6 candidates that met the constraint. All six of these options remained after step 3. The benefit/cost ratio for the options for unit A is 1.22, for unit C, 2.42. In addition to eliminating unsatisfactory options, step 3 provides the actual benefit to be expected (step 2 provides only a linear sum approximation) and the best sequence for implementation.

Table 1 shows the progress of the unit A candidates through the three steps. Analysts applied the procedure to each of the years of the 10-year period being examined. The method facilitated the orderly, logical, and defensible selection of the optimal set of options and met time and capital requirements. An important value of the method is that it enables users to determine the sensitivity of expected economic benefits to the vagaries of actual MTBF, MDT, and costs. Users can readily perform "what-if" analyses to facilitate program planning.

Table 2 documents a benefit/cost analysis of the proposed original plan and compares it with the plan resulting from the application of the availability improvement analysis. Both result in approximately the same net dollar benefits, but the changed plan costs nearly 30% less to implement, a saving of over $6 million.

EPRI is considering additional applications. When they have been completed, a report will be prepared and distributed. Future plans include attempts to completely automate the procedures (some of which are now performed manually) and make them operable on a personal computer. *Project Manager: Jerome Weiss*

Table 2
BENEFIT/COST ANALYSIS

	Original Plan	Optimized Plan
Total cost (1986 $)	$20,703,000	$14,603,000
Total present worth of benefits	$38,662,000	$33,019,000
Benefit/cost ratio	1.87	2.26
Total net benefits	$17,959,000	$18,416,000
Expenditures saved		$ 6,100,000

FIRST-GENERATION FUEL CELLS

First-generation phosphoric acid fuel cell generators (11 MW) are now available to utilities that are considering adding capacity in the early 1990s. Fuel cell power plants, which use natural gas, petroleum distillate, or synthesis gas from coal gasifiers as the primary fuel source, offer significant advantages: fuel conservation and flexibility, minimal environmental effects, dispersed siting, quick deployment, and ease of cancellation. The primary objective of EPRI's fuel cell research program is to expedite the introduction of commercial-type fuel cell systems for dispersed siting applications. EPRI activities are part of a much larger, nationally funded effort to make the fuel cell option available by the early 1990s.

EPRI is currently involved in three major efforts undertaken to expedite the commercialization of phosphoric acid fuel cell systems.

▫ Monitoring the performance and endurance tests of a United Technologies Corp. (UTC) 4.5-MW net ac fuel cell module on the system of Tokyo Electric Power Co. (Tepco), Japan.

This utility-oriented effort is designed to demonstrate that utility personnel can install, operate, and maintain fuel cell equipment and that the systems are technically ready for commercial utility applications.

□ Upgrading the 4.5-MW UTC demonstrator design into a configuration suitable for commercial utility applications (RP1777). Efforts in this area are aimed at reducing capital costs and improving plant reliability, maintainability, and durability. Emphasis is on the development and verification of key power plant components.

□ Defining a 7.5-MW module based on Westinghouse Electric Corp.'s air-cooled fuel cell technology (RP2192). EPRI is sponsoring development and verification of the plant's steam reformer and fuel-processing system.

Table 3
TEPCO 4.5-MW MODULE RESULTS*

Net power produced (kWh)	5,428,240
Load hours	2,423
Standby time (h)	464
Total generating time (h)	2,887
Fuel cell hot time (h)	4,098
Fuel cell thermal cycles	50
Reformer hot time (h)	4,233
Reformer thermal cycles	68

*Cumulative to December 13, 1985.

Demonstration systems

Tepco completed all power generation tests of its 4.5-MW fuel cell module December 13, 1985. Approximately 45 test runs were conducted over a 2.5-year period, during which the plant provided electricity to the Tokyo metropolitan area. These tests, monitored by EPRI, confirmed the performance, environmental, and transient response characteristics of the fuel cell module. Tepco reported that the system's efficiency (fuel to net ac power) at near full load (4.2 MW) was 37.5% (9100 Btu/kWh) based on the higher heating value of the fuel. This was 2.3% better than the expected design value. The efficiency at 50% load averaged 35%. The fuel cell stack assemblies performed exceptionally well: fuel conversion efficiencies (hydrogen to dc power) averaged about 58% and were constant during the endurance tests (operating at 2 MW). Fuel processor and inverter efficiencies (also at 2 MW) averaged about 70% and 94%, respectively, and both were fairly constant.

Measurements of environmental factors confirmed that fuel cells are suitable for use in environmentally constrained urban applications. Tepco reported that nitrogen oxide concentrations from the module were 3–12 ppm (based on 7% O_2 conversion). The fuel cell discharged 25% less nitrogen oxides per megawatt than conventional generators on Tepco's system. Sulfur oxide concentrations were undetectable (<10 ppm). Acoustic noise, measured 100 ft (30 m) from the module, was within the design objective of 60 dB(A). Most of the noise came from the turbocompressor, blowers, and cooling tower fans.

Tepco's first-of-a-kind fuel cell module was put through numerous startup, shutdown, and standby-to-load transitions. These confirmed the system's transient response and cycling characteristics and also enabled Tepco to better assess the durability of system components (Table 3). Tepco's endurance program and the resultant component stress tests were rigorous. The frequency of thermal cycles was often 10 times higher than would be expected under intermediate duty operating conditions (e.g., the steam reformer underwent 68 cold-to-hot thermal cycles). The fuel cell assemblies, the most delicate components in the system, proved to be extraordinarily rugged.

As expected, some design improvements were indicated for the ancillary components. The most significant were (1) improvements in the reformer burner and lowering the burner operating temperature to improve reliability and durability; and (2) a change from the custom-built, formed-plate-type heat exchangers supplied with the module to more reliable and more durable shell-and-tube exchangers.

Two EPRI-sponsored operators from Consolidated Edison Co.'s fuel cell program witnessed the operation of the Tepco unit and discussed plant operating experiences with Tepco's operators. They found that the test programs and operating procedures of Consolidated Edison and Tepco had much in common and that the Tepco operators had a good understanding of fuel cell plant operations. As a result of these discussions, the following recommendations were made.

□ Simplify the control system and improve procedures for diagnosing systems malfunctions

□ Change the control system as necessary to make it easier for the operator to make software changes related to system adjustments

□ Eliminate unnecessary shutdowns and trips caused by redundant and frequently overdesigned sensing instrumentation and software

□ Improve access to system components

Because of the success of these demonstration tests, Tepco has begun a study of an 11-MW system to address the unique design and packaging requirements for fuel cell power plants in the Tokyo metropolitan area. Tepco has expressed a strong interest in working together with U.S. utilities in the commercialization of the fuel cell option.

EPRI has been working with Westinghouse in the development of a novel fuel processing system that converts hydrocarbon fuel into hydrogen suitable for use in the fuel cells. A full-scale, 1.25-MW steam reformer was designed, fabricated, and installed in 1985 under terms of a joint agreement between EPRI and Haldor Topsoe, Inc. (*EPRI Journal*, May 1985). The Westinghouse–Haldor Topsoe steam reformer is a modular unit (Figure 1). Six reformer tubes, or modules, each delivering 1.25 MW in equivalent hydrogen, based on Westinghouse fuel cell conditions, will be used in a 7.5-MW design. This modularity improves operational and maintenance flexibility and imposes virtually no risk or scaleup issues for multimegawatt-size fuel cell systems.

Performance and proof-of-concept tests were begun in March 1986 at Topsoe's Bay Port test facility near Houston, Texas. Initial test data confirm the good performance and operability characteristics of the reformer unit. Performance data have been obtained at 25, 50, 75, and 100% load conditions. A total of 800 operating hours and three cold-to-hot thermal cycles have been accumulated as of June 1986. Process and burner exhaust exit temperatures, fuel conversion, and pressure drop agree well with Haldor Topsoe's model prediction. Measured temperature profiles also compare very well with Topsoe's analytic model predictions. The test plans for the remainder of the year include performance mapping and transient and cycling tests.

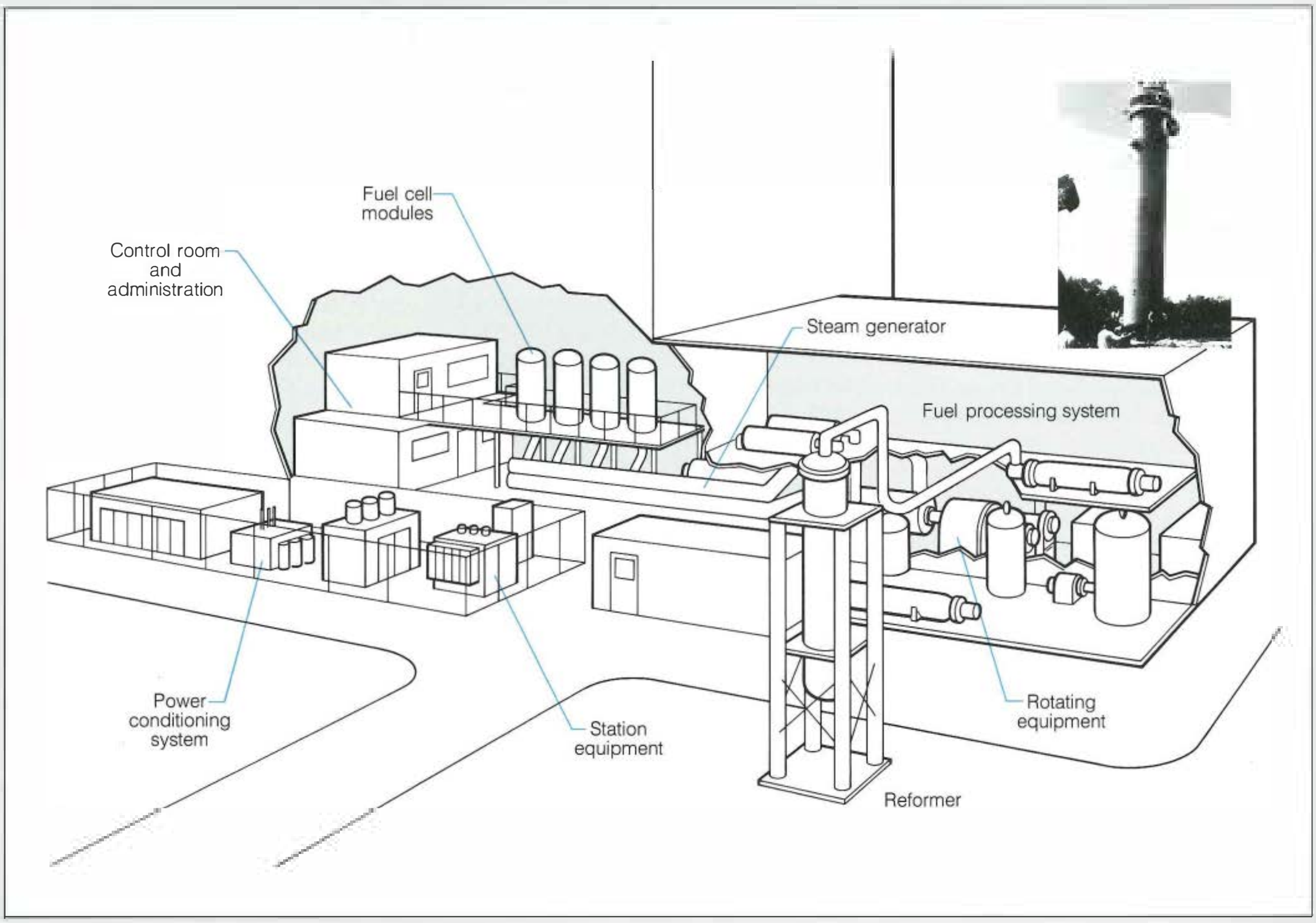
EPRI plans to make the fully verified 1.25-MW fuel processor technology available for use in the Westinghouse pilot power plant program, thereby reducing the technical risks and helping ensure the success of that program.

Commercial systems

EPRI funding and inputs from the utilities have helped UTC upgrade the design of the 4.5-MW fuel cell module into a commercially more desirable 11-MW (8300 Btu/kWh) configuration. UTC formed a joint venture company with Toshiba Corp. to manufacture, market, and service fuel cell generators on a worldwide basis. The new company, International Fuel Cells Corp. (IFC), is working with Bechtel to develop a standardized, prefabricated 11-MW fuel cell module that can be constructed on a utility site in 24 months.

To introduce the fuel cell option to the industry, IFC's commercialization program calls for sales of twenty-three 11-MW units (250 MW)

Figure 1 EPRI–Haldor Topsoe steam reformer (insert) installed for performance testing at Haldor Topsoe's facility in Houston, Texas. Each module will deliver hydrogen equivalent to about 1.25 MW. The reformer is a key component of Westinghouse's 1.5-MW pilot plant, a precursor of its proposed commercial-scale 7.5-MW fuel cell systems. Components of the pilot plant will be designed and procured to 7.5-MW specifications.



over the next year. The first commercial prototype plant could be operational as early as 1990.

Westinghouse has recently announced its intention to build a 1.5-MW pilot power plant as the next step in its commercialization program. The 1.5-MW pilot plant will be a composite of full-size 7.5-MW systems and components, and it will be designed and procured to 7.5-MW specifications (Figure 1). Because the components will be operated at full-rated conditions, most of the risk and operational uncertainties of the 7.5-MW plant will be addressed and resolved in the pilot power plant program. The 1.5-MW plant will also provide an opportunity to incorporate design features and test programs requested by sponsoring utilities, and it will ensure that the eventual 7.5-MW commercial plant will meet the broadest range of utility requirements. Westinghouse is seeking support from 15 or 20 utilities for its program.

Phosphoric acid fuel cell power plants are now on the threshold of commercialization. Further research and development are necessary to achieve the cost reductions that will ensure success, but today's hardware is already well advanced and demonstrated. IFC is sufficiently confident of its proposed systems that it will expect no payment for its market-entry units until system performance is acceptable by utility standards. Fuel cell vendors are now looking to the utilities for help in their further efforts to move ahead with the commercialization process. And EPRI stands ready to help member utilities with the technical and economic evaluations of fuel cell power plants that will enable them to make early purchase decisions. *Project Manager: D. M. Rastler*

R&D Status Report
COAL COMBUSTION SYSTEMS DIVISION

Kurt Yeager, Vice President

CYCLING FOSSIL FUEL PLANTS

Coal-fired generating plants designed for steady baseload operation today are being used to accommodate swings in daily electricity demand. Two factors are responsible for this switch to cycling operation. First, nuclear power plants begun as long as 10–12 years ago are now coming on-line; designed for baseload, these plants have lower fuel costs and are required by regulatory mandate to be in essentially steady-state operation. Second, overall electricity demand growth has slowed, and the baseload is not rising fast enough for many coal-fired plants to keep operating at their design rating; thus they are being relegated to on-off cycling or subjected to reduced-load operation. As a result, damaging fatigue stresses are being imposed on the thick-walled components of fossil fuel boilers and turbines. By reducing the expected life of this equipment, such stresses can lead to lowered availability and large capital expenditures. Other concerns—inability to maintain combustion at very low loads, pump and feedwater heater failures, low efficiency of environmental control equipment—reinforce the need for improved designs and materials for cycling fossil fuel plants. EPRI R&D is aimed at solutions to all these issues.

Daily load profiles accentuate the dilemma that many utilities face. In a typical example, Duke Power Co. recently projected a need for extensive fossil fuel plant cycling. As indicated by the utility's projected load pattern for the 1988 summer peak (Figure 1), not only are fossil fuel units required to cycle, but load variations may be required for nuclear units as well.

The primary concern raised by cycling is temperature change: its effects are dictated by its frequency and extent. In the space of a year, a baseload plant may be brought down (or taken off-line) only 10–12 times, whereas a cycling plant may be brought down more than 150 times. Some of these cycles may involve only a retreat to a reduced load, but many involve a complete turndown to zero load. If a turndown is only overnight, then steam conditions are maintained, the machine cools only moderately—say, from 1000 to 900°F (540 to 480°C)—and a hot start follows. If the turndown is for a weekend, then firing ceases, the system temperature falls to 700°F (370°C), and a warm start follows. A shutdown of six days or more allows the entire machine to stabilize at ambient temperatures, and a cold start is required.

These cycles call for different operating sequences, with different rates of temperature change both as the unit is brought down and as it is brought on-line again. Cycling is costly because there is economic value in the time required to get on-line. But a greater concern is the danger of plant outages due to cumulative fatigue damage or other cycling-related issues. The major potential problems are listed below.

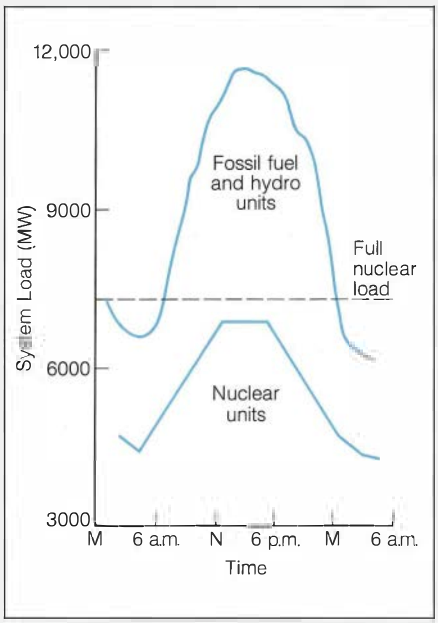


Figure 1 In Duke Power Co.'s projected load pattern for the 1988 summer peak, both nuclear and fossil fuel plants must be cycled to meet the intermediate and peak load. EPRI R&D is addressing the problems that could result from such operating scenarios.

- Boiler: fatigue stress on headers and steam lines, furnace implosion or explosion, flame-scanning problems at low load, burner and pulverizer turndown, mill fire or explosion
- Turbine: fatigue stress on the rotor, casings, and valves; solid-particle erosion; vibration during startup and shutdown; wear of turbine water seals
- Environmental controls: acid dew point condensation, precipitator turndown, scrubber reagent control
- Water quality: water chemistry monitoring, chemical cleaning

All these issues were discussed in a 1983 EPRI workshop (CS-3979).

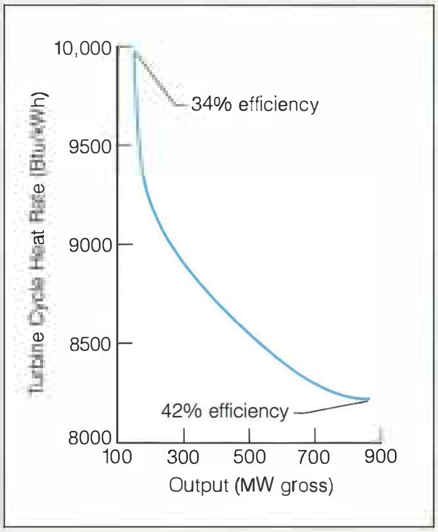
In addition to availability problems, cycling can lead to decreased efficiency. Heat rate degrades at low loads, as illustrated by data from Pennsylvania Power & Light Co.'s Martins Creek units (Figure 2). EPRI studies under RP1403 seek to reduce such efficiency losses through spiral-wound variable-pressure boilers, variable-speed fans and pumps, reduced auxiliary power to precipitators and scrubbers, and other innovations.

Turbine considerations

In general, transient stresses in large high-temperature components, particularly the rotor, constitute the primary cycling concern for turbines. These stresses can result in local surface yielding or even cracks. They arise because of temperature differences between the turbine metal and the steam during restarting, which lead to variations in temperature (and hence in metal expansion) across the thick wall of the rotor forging.

Such fatigue stresses reduce the time to failure, but because material strength varies significantly, even within the same rotor forging, it can be difficult to estimate remaining life with accuracy. Working stresses for the forging material also vary widely with location, so quite broad safety margins are generally required to ensure that turbine components have adequate life. On-line stress analyzers have been

Figure 2 Data from Pennsylvania Power & Light Co.'s Martins Creek station show that turbine cycle heat rate rapidly worsens at low load. EPRI R&D is seeking to minimize such efficiency losses.



developed to monitor the adverse conditions that can limit rotor life.

Large external turbine bypass systems, commonly used in European plants, can enhance both the startup flexibility and the load-changing capability of a unit. Many of the newer European units are equipped with bypasses sized for 100% steam flow, which permit rapid unit reloading even after full-load rejection down to auxiliary house load. Such a system allows full steam flow to be diverted from the turbine without causing major pressure changes in the boiler. It also ensures large volumetric flows during startup—and thus high velocity in the superheat and reheat boiler sections, which is necessary for maintaining low tube temperatures. In short, turbine bypass systems facilitate plant startup and loading, independent operation of boilers and turbines, and boiler drum temperature control; reduce solid-particle erosion damage; and promote stable system performance.

The technical and economic aspects of bypass systems are discussed in CS-3717. A follow-on project (RP1184-3) that evaluated existing bypass systems and developed guidelines for optimizing system size is documented in CS-3800.

Supercritical turbines in service in the United States appear particularly unsuited to two-shift operation, although this capability would now be desirable for many utilities. Japanese and European designs have some features that can enhance such duty—features that stem from an early need in those countries for flexible, midrange operation. Future U.S. supercritical units may benefit from some of these innovations, including fast automatic startup systems, spiral-wound variable-pressure boilers, turbine bypass systems, full-arc admission, and integrated on-line stress analyzers for boilers and turbines. All these issues are being studied under RP1403, research on improved coal-fired power plants (CS-4029).

Boiler considerations

Cyclic stresses created by changes in temperature are also significant in boilers. There they can arise from temperature differences within the thick walls of certain components (e.g., steam drums, superheater outlet headers) or from temperature differences between contiguous components (e.g., superheater or reheater tubes connected to outlet headers, nonpressure parts attached to tube walls). Table 1 chronicles recent examples of typical cycling-related problems that can occur in boiler components.

In an early project in this area, EPRI performed an analytic and experimental study of transient boiler operation at Tennessee Valley Authority's Widows Creek-7 and developed an analytic model to simulate boiler startup (CS-2340). Subsequently, a boiler thermal stress and condition analyzer was developed by EPRI and Combustion Engineering, Inc. (RP-1893-1). The analyzer was installed at the Ravenswood plant of Consolidated Edison Co. of New York to monitor boiler components during episodes of high thermal stress or high-temperature operation; it now operates on-line to assess accumulated damage to headers, steam lines, and other components. Such boiler stress analyzers are considered essential as diagnostic tools for cycling fossil fuel units and for life-extended plants.

Deteriorating water quality and ensuing water-side corrosion constitute another major problem that typically is worse at the low loads often experienced in cycling units. The infiltration of oxygen and the transport and deposition of silica, copper, and iron are the causative agents of such corrosion. All areas in the water-steam cycle require attention—feedwater, boiler water, steam, condensate, and makeup water.

RP1184-9 is investigating the effects of cycling operation on corrosion-product transport through the water-steam cycle. As part of this project, NWT Corp. is sampling water for chemical analysis from selected locations in the preboiler system at Florida Power & Light Co.'s Port Everglades station, a cycling plant. Recommendations are being developed to minimize the transport of corrosion products during cycling operation and thus to reduce boiler and turbine corrosion-related failures. Controlling the peak oxygen concentration in the condensate during shutdowns shows the most promise for corrosion control. For example, inhibiting oxygen ingress by maintaining condenser vacuum overnight can reduce iron transport to the boiler tenfold.

The impact of cycling on environmental controls has been addressed in a planning study by Bechtel Group, Inc. (RP1184-6). This study analyzed the critical issues associated with the cycling and turndown of plant emission control equipment, including the optimal operation of electrostatic precipitators and scrubbers, the control of reagent feed in wet scrubbers, and the performance of fly ash handling equipment. The study outlines R&D for each critical issue and a technical plan for follow-on work. The final report will be published this fall.

Simulating the dynamics of plant startups can help utilities understand and optimize the interaction of all plant components. Much progress has been made in this area. The development of the modular modeling system (MMS) has resulted in a computer code that can model the thermodynamic and control processes of the boiler, turbine, and balance-of-plant systems (RP1184-2). The current MMS library has more than 100 modules representing various fossil fuel and nuclear plant components; these self-contained modules can be

Table 1
EXAMPLES OF CYCLING–RELATED BOILER PROBLEMS

Utility	Unit	Failure	Probable Cause
Philadelphia Electric Co.	Eddystone	Main steam line cracking	Thermal cycling
United Illuminating Co.	New Haven Harbor	Header bowing	Condensate flow due to forced cooldown
New Zealand Electric	Huntly-1	Header bowing, header support cracking	Condensate flow due to rapid cycling
Ontario Hydro	Lakeview	Economizer cracking	Thermal shock due to slug feeding
Wisconsin Electric Power Co.	Port Washington	Drum cracking	Thermal transients due to flow stratification

interconnected to fit any plant configuration (CS/NP-3016). A simple version of MMS, a dynamic plant model that runs on an IBM PC, has been developed to evaluate different plant startup procedures (RP1184-4). Demonstration diskettes of this model are available for use by utilities.

Strategies and guidelines

EPRI has recently launched a major utility demonstration program to develop cycling conversion guidelines. Teams representing utilities, manufacturers, and architect-engineers will work on strategies and guidelines for converting baseload fossil fuel units to cycling duty. Four units have been tentatively selected for conversion. These units and their project teams are as follows.

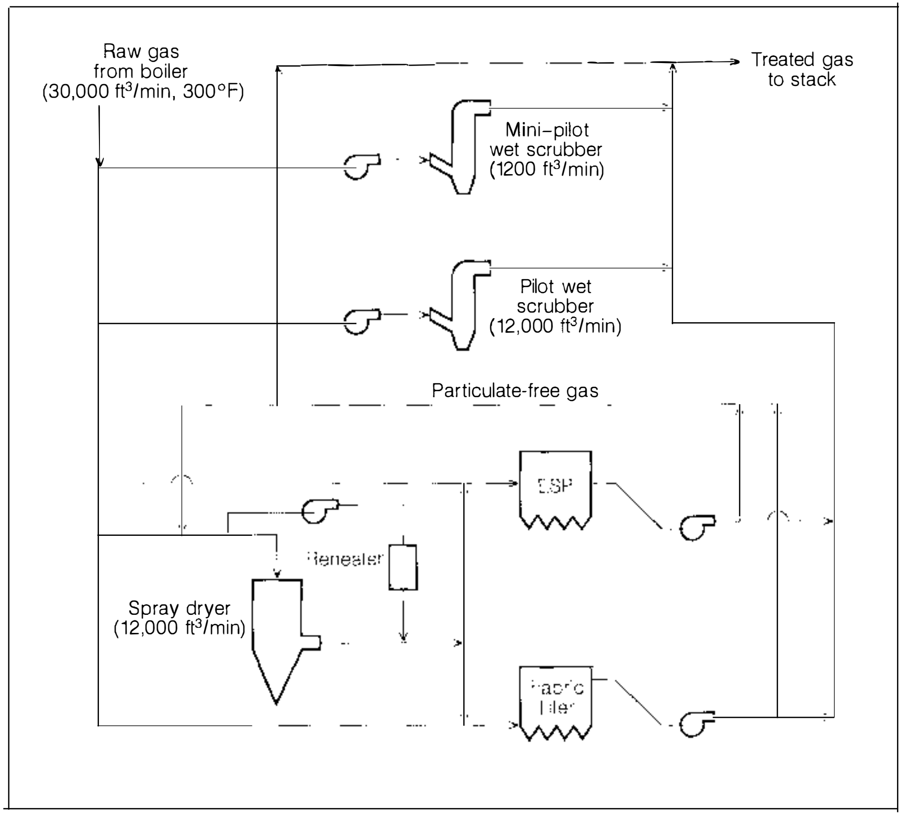
- Hudson-2 of Public Service Electric & Gas Co. (coal-fired, supercritical): Foster Wheeler Energy Corp., Westinghouse Electric Corp., Sargent & Lundy (RP1184-16)
- Potomac River-5 of Potomac Electric Power Co. (coal-fired, subcritical): Combustion Engineering, Inc., General Electric Co., Gilbert/Commonwealth (RP1184-21)
- Moss Landing-7 of Pacific Gas and Electric Co. (oil/gas-fired, supercritical): Babcock & Wilcox Co., General Electric Co., Ebasco Services, Inc. (RP1184-20)
- Oswego-5 of Niagara Mohawk Power Corp. (oil/gas-fired, subcritical): Foster Wheeler Energy Corp., Westinghouse Electric Corp., Stone & Webster Engineering Corp. (RP-1184-17)

The generic guidelines, to be issued in late 1987, will be developed on the basis of the four utility conversions by a central coordinator (Gilbert Associates, Inc.) under RP1184-19. *Project Manager: Anthony Armor*

HIGH-SULFUR TEST CENTER

With major cofunding from New York State Electric & Gas Corp., Empire State Electric Energy Research Corp., and the New York State Energy Research & Development Authority, EPRI is sponsoring a $20 million center for research on emission control technologies for power stations burning high-sulfur coal (RP2604). Currently under construction at NYSEG's Somerset station near Buffalo, the High-Sulfur Test Center (HSTC) will be a comprehensive facility for testing control technologies at various levels of development up to 4 MW. All emissions will be addressed—sulfur dioxide (SO_2), particulates, nitrogen oxides (NO_x), solid waste, and wastewater. For flue gas desulfurization (FGD), the facility will initially include a 4-MW spray-dry absorber, a 4-MW wet scrubber, a 0.4-MW wet scrubber, and laboratory-scale scrubbing equipment. For particulate control it will have a fabric filter and an electrostatic precipitator (ESP), either of which can be used before the wet-scrubbing pilot units or before or after the spray dryer.

Figure 3 HSTC flue gas flow. The facility is designed to provide great flexibility in studying equipment options and process variables for FGD and particulate control in plants burning high-sulfur coal. (Flows are given in actual ft³/min.)



HSTC objectives

Growing concern over acid rain is causing the utility industry to continue its efforts to develop advanced, low-cost SO_2 and NO_x control strategies. With the passage of the Clean Air Act Amendments of 1970 and 1977, continuous SO_2 control became a requirement for all new coal-fired power stations. By the end of 1984, over 90,000 MW of generating capacity had been committed to the installation of FGD systems. Over 90% of these systems are lime or limestone wet scrubbers. Although these systems are based on a relatively simple concept, in practice the technology has proved to be complex and expensive. Early installations were characterized by excessive plugging of ductwork and process equipment, severe corrosion, generally poor reliability, and hence high operating and maintenance costs. To address these issues and to develop improved processes for emission control, EPRI has established a large FGD research program. The HSTC will be one focal point for this work, complementing the efforts on low-sulfur coal at EPRI's Arapahoe Test Facility in Denver, Colorado.

The overall goal of the HSTC is to reduce the complexity and cost of emission control technologies for coal-fired power plants. Specific objectives are as follows.

- To improve existing FGD processes in terms of SO_2 removal efficiency, energy use, reagent utilization, by-product formation, and reliability
- To evaluate and develop new emission control processes (such as high-sulfur spray drying, all-dry SO_2 adsorption, and combined NO_x-SO_x processes) that can cut emission control costs up to 50% while reducing wastewater and improving solid by-products
- To investigate conditions that have led to emission control problems in full-scale utility units by duplicating them at a smaller scale, where alternatives can be more quickly and cost-effectively evaluated
- To gain a better understanding of FGD process chemistry and system operability, in part by developing and testing an FGD chemistry

model that can predict performance and diagnose problems

▫ To prevent the premature commercialization of underdeveloped control technologies

Process equipment

The HSTC will feature wet-scrubbing test facilities at bench scale (5 standard ft^3/min; 2.36 dm^3/s), mini–pilot scale (0.4 MW), and pilot scale (4 MW). It will also have a 4-MW spray-dry absorber that can use a fabric filter or an ESP for particulate control. Whichever of the two is not being used with the spray dryer will remove particulates upstream of the wet-scrubbing pilot units. Under special circumstances the ESP can be used upstream of the spray dryer–fabric filter configuration as well. Figure 3 shows flue gas flow in the major components of the HSTC. The composition, temperature, and flow rate of the inlet gas can be controlled separately for the mini–pilot scrubber, the pilot scrubber, and the spray dryer. In short, the HSTC offers considerable flexibility in terms of flow configuration and flow control and measurement.

The bench-scale scrubbing facility will be used to examine and optimize individual process steps before they are integrated into a comprehensive process. Process variables can be studied more easily at this scale because the required liquid and solid residence times are much shorter than in a large-scale pilot or commercial unit. The facility will be able to use either a simulated flue gas or gas obtained from the Somerset station and then treated for particulate removal. The main objectives of the bench-scale work will be to provide support for solving process problems in the HSTC pilot units and to screen new technologies. The facility will also be available to perform troubleshooting for commercial units.

The 0.4-MW mini–pilot scrubber consists of an absorber, a reaction tank, and a dewatering centrifuge. This scale, the smallest at which commercially available equipment can be used, allows the testing of fully integrated processes while minimizing the cost of process modifications. The pilot-scale scrubber is an order of magnitude larger, at 4 MW, and represents the smallest size at which the scale-up information necessary for designing full-scale equipment can be obtained. Various equipment options are possible with the pilot unit, including two different slaking and grinding systems, four different dewatering systems, and several types of packing and mist eliminators.

The spray dryer pilot, also 4 MW, will make possible side-by-side comparisons of spray drying and wet FGD technologies. The equipment, which represents current utility design, enables several conventional and advanced configurations to be simulated, including various reagent feed schemes, various water use schemes, and solids recycling. Recent economic studies indicate that installing a spray dryer–fabric filter combination to follow an existing ESP can be a cost-effective retrofit SO_2 control alternative. Thus this configuration will be tested at the HSTC.

Figure 4 presents a preliminary schedule showing some of the major HSTC test programs planned for the first five years. The emphasis is on the acquisition of performance data and the development and validation of models, with utility problem-solving efforts interspersed.

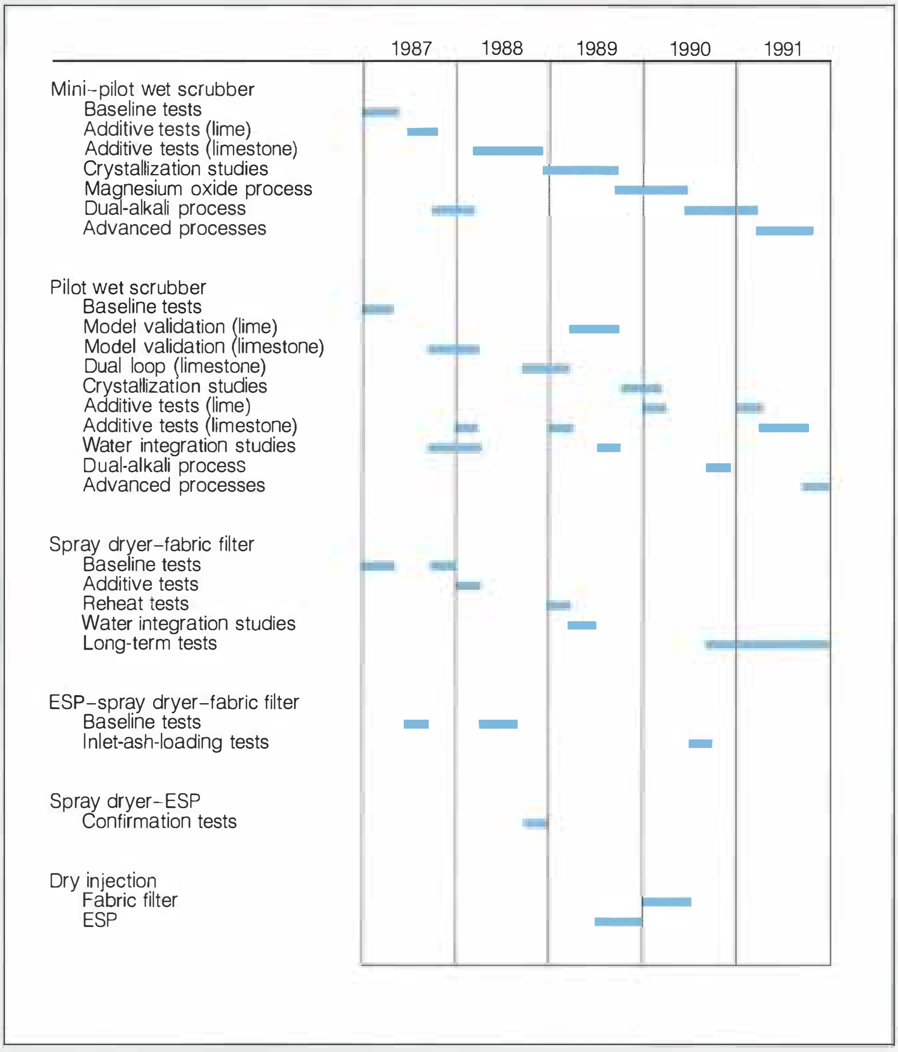


Figure 4 Proposed five-year test schedule for the HSTC. The program will address most current commercial FGD systems as well as such advanced designs as high-sulfur spray drying and dry sorbent injection. The use of various additives and novel water injection schemes will also be investigated.

Project status

The HSTC, which consists of a main test building and a warehouse-administration-shop facility, is being constructed under five fixed-price contracts managed by Gilbert/Commonwealth. Construction is nearly completed. The major process equipment was delivered this summer and is in place. Instruments and controls are now being installed. Startup is scheduled for the end of this year, and testing is to begin in early 1987.

Working with its advisory structure and the major HSTC cofunders, EPRI is building a facility that will address the industry's needs for emission control research for power plants burning high-sulfur coal. When complete, the facility will provide a test bed for every stage of development from the laboratory to the large pilot and will accommodate many different types of emission control equipment. Work at the HSTC, together with other industry efforts, should lead to improved emission control performance at lower cost. *Project Manager: Charles Dene*

R&D Status Report
ELECTRICAL SYSTEMS DIVISION

Narain G. Hingorani, Vice President

UNDERGROUND TRANSMISSION

Material variables in water treeing

Although examined extensively for 15 years, the water-treeing problem in extruded dielectric cable insulation has not proved easy to solve. Water treeing occurs when polyolefin insulation is subjected to voltage stress in the presence of water. Voids, contaminants, and discontinuities are sites from which such defects grow. The treelike patterns that develop reduce dielectric strength; electrical failure then occurs. The problem has been discussed in other *Journal* articles (e.g., July/August 1984, p. 51).

From a basic research perspective (i.e., trying to understand the phenomena involved), it is unfortunately true that polyethylene (PE) is a very difficult material with which to work. Composed solely of hydrocarbon chains, the structure may appear simple; however, it is very complex.

PE is semicrystalline, meaning that it has both crystalline and amorphous regions. Cable-grade PE is highly branched, and the branches can be quite long. When crosslinked, it has a gel and sol fraction, and they have different properties at elevated temperatures; the sol/gel ratios can also vary from cable to cable. Furthermore, XLPE contains crosslinking agent by-products (perhaps five or more) and residual peroxide. PE must also be stabilized to prevent degradation during extrusion: hence, antioxidants and the degradation products are always present. All these factors serve to complicate methods to facilitate understanding.

To minimize or eliminate these problems, EPRI is sponsoring a basic study on water treeing, using polystyrene (PS), a polymer that does not present these complications. PS is also a hydrocarbon polymer, but it is completely glassy in nature (i.e., amorphous). Crystalline PS can be prepared in the laboratory, and, unlike PE, it can be incorporated into PS in a controlled manner. When styrene is converted into the polymer, it can also be crosslinked in a controlled manner by using divinylbenzene, a structural analogue to styrene. Stiffness can readily be controlled by incorporating PS oligomers (low-molecular-weight PS). Special techniques can be employed to control contamination and voids. In short, PS is an easier material to use for studying the fundamental phenomena involved in water treeing.

The University of Connecticut's Institute of Materials Science is currently conducting the research (RP7897-10). A three-year study was started in 1985. Researchers expect to isolate many of the underlying factors influencing water treeing and, as a result of this work, better understand the phenomena. *Project Manager: Bruce Bernstein*

OVERHEAD TRANSMISSION

Transmission line structural development

The present pressures on the electric utility industry to use less obtrusive structures, use less right-of-way, use less desirable rights-of-way, and respond more quickly to short-term needs require that new designs and new design concepts be available in a shorter time span at less cost.

A long-term payoff of this project will be the ability to accurately simulate transmission structural system loads and response without testing. Currently, experience through testing is the only way to verify structural designs. Major structure innovations can take 10 years or longer to develop, using a proof-test-only approach. In the short term, improved software, which takes advantage of today's computer technology coupled with the improved testing techniques available at Transmission Line Mechanical Research Facility (TLMRF), can reduce development time and improve designs. The role of RP2016 is to provide the structural software expertise to meet the research objectives of the TLMRF structural development project; RP1717 provides the full-scale testing expertise to gather the basic data needed by the research project.

The long-term goal of the TLMRF research program is to develop the technology necessary to accurately simulate the static and dynamic performance of transmission line systems and components. This objective involves the concept of line-simulation, which is concerned not only with how components—e.g., structure, foundation, conductors—act independently but also with how they perform as a unified system. The capability will permit engineers to improve existing designs and analyze with confidence such things as the failure containment or anticascading characteristics of the line. To provide this capability, improved analysis tools are required that can compute the initiation of component failure as well as the postfailure response of the total system.

The overall project objective is being accomplished by (1) improving design and analysis software on the basis of results obtained from full-scale structure tests conducted at the TLMRF, (2) maintaining a data base on the TLMRF test results, (3) evaluating new design methodologies, and (4) integrating structural analysis and design software into the EPRI TLWorkstation* software system.

To date the project has quantitatively defined how well existing analysis tools compute the response and failure mechanisms of transmission structures. Some improved analysis techniques have been identified and/or developed to improve the capability to simulate the static behavior of transmission structures. Testing capability has been developed and hardware installed at the TLMRF to perform and record dynamic tests on a section of actual transmission line. State-of-the-art finite element software has been developed and in-

*TLWorkstation is an EPRI trademark.

stalled in the TLWorkstation system to allow future improvements to be plugged into the present software system.

Of the 25 full-scale tests performed at TLMRF, 18 have been cosponsored by utilities. *Project Manager: Paul Lyons*

Insulator contamination monitor

Researchers in contamination studies need an instrument that is not only simple and inexpensive but also reliable and accurate for measuring airborne contamination at a site or series of sites. Such a device has been developed for EPRI at the High-Voltage Transmission Research Facility (HVTRF). Although the main reason for developing this instrument is to predict the contamination that will collect on HVDC transmission line insulators, researchers can use it whenever they have to measure the level of air contamination.

Figure 1 shows this instrument, called an insulator environmental contamination monitor (IECM), installed in the field. Two small wires are energized at −8.5 kV; the collecting plate is energized at +8.5 kV. The wires produce negative ions that charge the particles in the air flowing near the IECM, and the negatively charged particles are attracted to the positively energized lower plate. The upper plate provides rain shielding.

At specified intervals, the collecting plate is removed and sent to a laboratory for measurement of the quantity (and type, if desired) of collected contaminants. The two dc voltage supplies are mounted under the top plate and are powered by either a 120-V ac source or two 12-V car batteries. In field tests, IECM has proved to be rugged, reliable, and easy to maintain.

The first IECM application will determine how much contaminant will collect on HVDC line insulators. Because local contaminants are an important consideration in the design of HVDC lines, the plan calls for installing several IECMs along a proposed transmission line route. Knowing the relationship between the contamination collected by the IECM and the amount deposited on actual dc insulators, a transmission line engineer can specify an efficient insulation design.

In the past, a major problem has been the time required to measure insulator contamination, a process that could take several years. IECM is much more efficient in collecting dust; therefore, meaningful measurements can be made after only about three months, and the collection time for insulation design may be reduced to less than one year.

For calibration, researchers are placing IECMs near operating HVDC lines, where they will compare contamination on the monitor and the insulator. A similar calibration is to be developed for station post insulators and bushings at dc converter stations.

Twenty-five of the monitors have been constructed, and more will be built if demand is sufficient. Persons interested in obtaining more detailed information are invited to contact Dr. Don Deno at the HVTRF, (413) 494-5196. *Project Manager: John Dunlap*

DISTRIBUTION

Lightning flash location

The East Coast lightning detection network, described in the June 1984 *EPRI Journal* (p. 46), has been in full operation since early 1985, and more than 3.6 million flashes were recorded during the year. We now have recorded data on 5.1 million flashes, counting the 1.5 million recorded in previous years. Researchers have collected data on the peak radiation field strength and the polarity and number of strokes per flash (multiplicity), as well as the geographic location for each flash (RP2431).

To say that processing all these data into forms usable by surge protection engineers is a large job is an understatement. However, the contractor, State University of New York at Albany (SUNYA), has devised efficient processing techniques to produce the desired output.

For example, project personnel have prepared contour maps showing the ground flash density (in flashes per square kilometer) for the area of the network under surveillance. These maps, of course, are not yet statistically accurate, being based on a minimum data-gathering period. As years pass, however, the statistical validity will improve. It is also possible to determine peak flash densities, which are meaningful statistics for some designers.

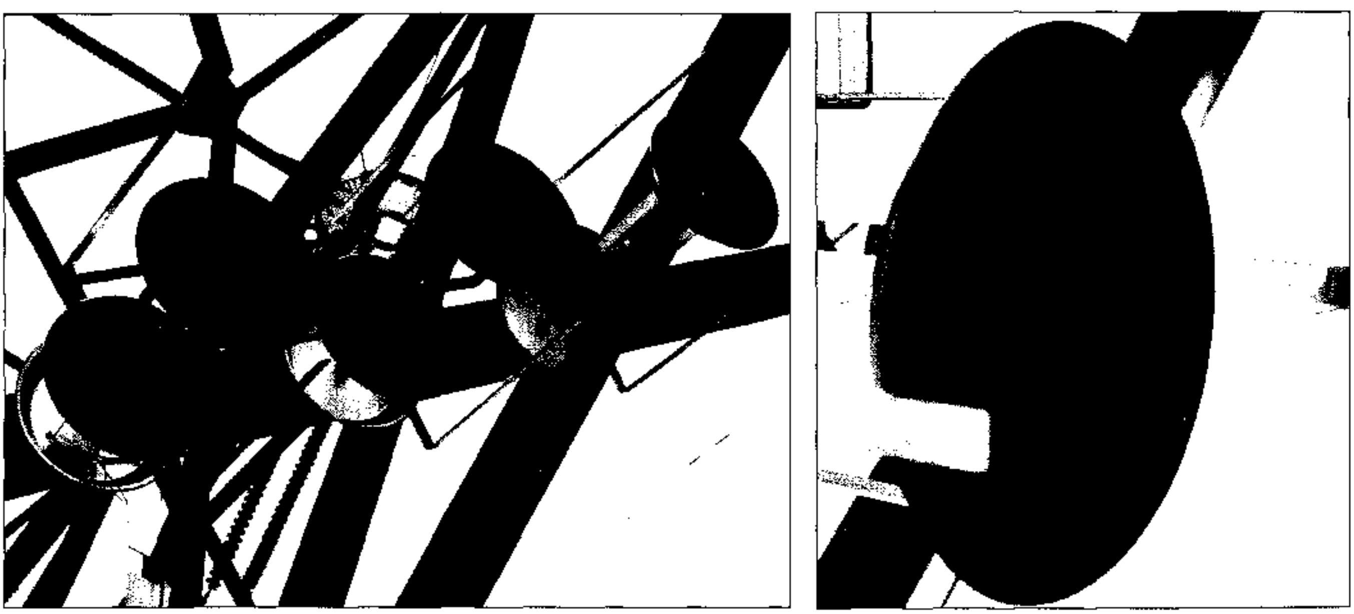


Figure 1 Field installation of an IECM showing three units mounted on a crossbeam at the conductor elevation. On the two energized units on the left, the collectors (bottom plate) are darker than the unenergized unit on the right, showing the enhanced contamination collection. The +8.5-kV power supply can be seen under the top left plate. Close-up (right) of the collector plate and the two small wires energized at −8.5 kV. The blackened plate is energized at +8.5 kV.

Another flash characteristic that relates both to density and to surge protective equipment durability is multiplicity—the number of strokes in each flash. Each lightning discharge event—the flash—consists of one or more return strokes, or simply, strokes. Each stroke subsequent to the first represents another opportunity for insulation to spark over, albeit with reduced probability because the current in subsequent strokes is usually lower than that in the first stroke. Furthermore, each stroke delivers additional charge, which translates into energy that surge arresters must discharge.

At this time, we cannot estimate the charge in strokes, but the research team may be able to make reasonable estimates in the future. For now, the team is counting strokes and summarizing the results. Data gathered have shown that negative flashes average over two strokes per flash, whereas positive flashes predominantly consist of only one stroke.

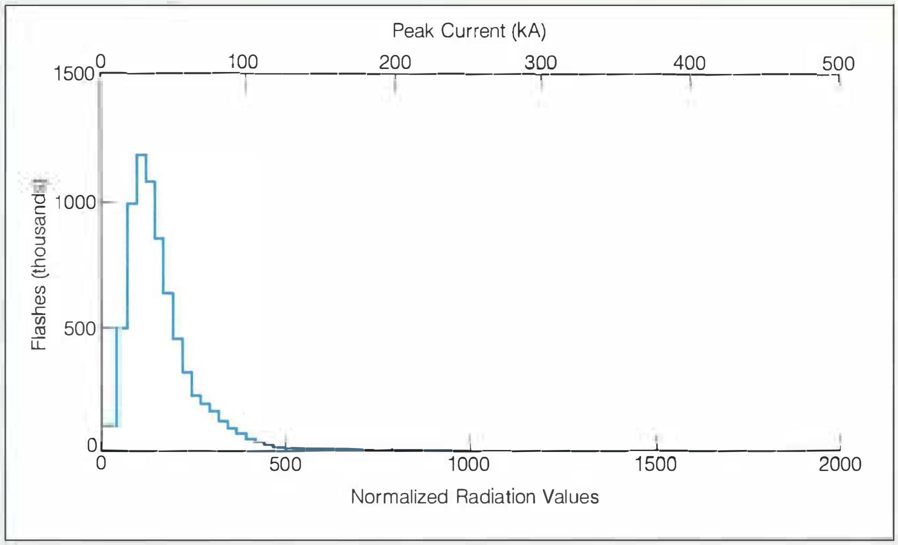
Although flash polarity is not an important input parameter to insulation coordination studies, it is automatically recorded, and data analysis shows some interesting results. During the summer lightning season, negative polarity predominates, confirming the assumption that researchers have always made. In winter storms, however, the reverse appears to be true—positive flashes approach a peak of 80% of all flashes. Although the impact of this phenomenon is minimal because of the vastly reduced flash rate in winter, there may be some implications for those insulation systems that have lower sparkover for positive polarity than for negative.

Characteristics of lightning discharges that surge protection engineers want to know about are peak current and rate of current rise. Lightning location equipment cannot provide this information directly, so researchers have devised a methodology for estimating peak current. The detection system provides the peak radiation field of each first-return stroke. By normalizing the peak radiation fields, researchers can obtain the statistical distribution of field strength. Previous lightning research, in which the lightning current passing through stricken towers was actually measured, has resulted in the determination of the median current in lightning strokes. By relating the median field strength to the median current and knowing the distribution of the radiation field magnitudes, researchers can estimate the current magnitude distribution. Figure 2 illustrates the application of this methodology for more than 600,000 negative first return strokes, and Figure 3 for more than 15,000 positive first return strokes for the same period. As we have seen, positive and negative discharges differ markedly in multiplicity and temporal predominance, and these illustrations point out additional differences—the sheer predominance of negative flashes in quantity and a generally higher current content of positive flashes.

The methodology for estimating lightning currents is based on several important assumptions, which make the accuracy of the results somewhat uncertain. However, an analysis of the effect of the variability of the assumptions leads us to conclude that the results are fairly accurate, provided that the basic assumption of the median current in lightning discharges is accurate. Researchers will continue to pay close attention to this aspect, as well as to the estimation of rate of rise.

One important by-product of the lightning detection network is that EPRI member utilities can have access to the data network in real time. Such access allows them to watch storms approaching their service areas, observe the severity of a storm, and estimate its

Figure 2 The radiation fields of more than 600,000 negative first return strokes were measured and then normalized to 100 km. The lower abscissa of this histogram shows the distribution of the radiation values; the ordinate shows the number of flashes. The current distribution is estimated by scaling the median current, based on other research, to the median abscissa.



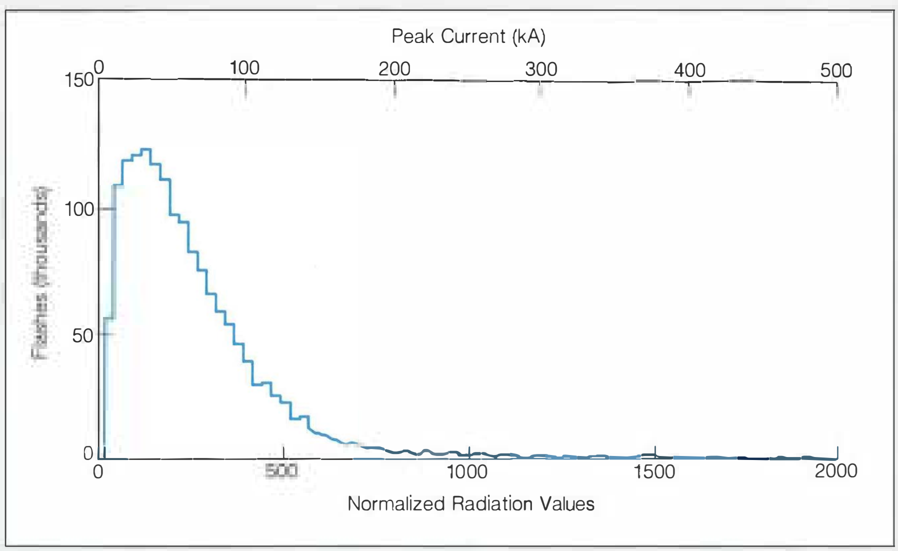


Figure 3 The construction of this histogram for more than 15,000 positive first return strokes is similar to that of Figure 2 and uses the same median reference point established by the much larger number of negative stroke radiation values. The median positive current appears to be about 50% greater than the median negative current, and there is a significantly greater percentage of strokes having more than 100 kA among positive strokes than among negative strokes.

track through their systems. Distribution engineers, as well as system operations engineers, can readily appreciate the opportunity for advance planning that such real-time storm tracking would provide. At this time, seven utilities are taking advantage of this capability, and others are welcome to contact the project manager for information. This service is also available for a royalty charge to nonmember utilities and anyone else needing the information.

Lightning detection coverage will be extended in 1987 westward to the Mississippi River in the southern half of the United States. Similar expansion is planned for the northern half and the portion west of the Mississippi.

A report is now being prepared that will summarize the data gathered thus far. Although the total amount of recorded data is voluminous, it does not yet constitute a valid data base, so the report will be periodically updated. *Project Manager: H. J. Songster*

TRANSMISSION SUBSTATIONS

Static electrification control in power transformers

Static electrification is a significant new failure mechanism in power transformers that are cooled with pumped insulating fluid. The flow of fluid insulation past solid material results in the separation of static charges. Some static charges accumulate on the surface of solid insulating members and build up a voltage. Other charges are transported with the flowing fluid, building up concentrations of net voltage in some regions. If the voltage becomes large enough, insulation breaks down and the transformer fails. Controlling static charge generation is therefore of great importance to power transformer manufacturers and users.

Static electrification can exist in any transformer that pumps insulation fluid for cooling purposes. Even if the static electrification voltage does not result in an internal flashover and failure, it establishes a bias, making transformer insulation systems more vulnerable to breakdown from external transient conditions. Better understanding of the static charge phenomenon will enable us to control it.

The EPRI-sponsored investigations of static charge generation and charge transportation in Freon and SF_6 insulants have carried out significant research. In this project researchers in two studies are investigating charging characteristics of a nonflammable PCB substitute and mineral insulating oils (RP1499). Perchloroethylene (C_2Cl_4), various naphtha- and paraffin-based mineral oils, and mixtures of them are being examined. Improved transformer reliability is expected from this research.

In one of the studies, Westinghouse Electric Corp. has obtained 17 samples of oil from nine domestic sources. Researchers tested each oil for compliance with ASTM standard specifications and evaluated each oil's charging behavior relative to temperature, moisture level, exposure to light, and contact with container surfaces. They also evaluated a variety of sample containers for possible influence with respect to charging behavior. Project personnel attempted to isolate and identify charge-producing species in high-charging samples. Impulse strength tests have been made, and a flow model apparatus is currently being developed to examine partial discharge of oil moving at various velocities. Westinghouse is comparing charging tendencies and behavior of seven different mixtures of C_2Cl_4 and oil ranging from 100% C_2Cl_4 to 100% oil.

The other study in this project, by Massachusetts Institute of Technology (MIT), uses a unique Couette flow system apparatus to analyze electric fields generated by relative motion of oil and solid materials. The flow apparatus consists of concentric rotating and stationary cylinders with oil between them. The MIT study is focusing on basic theoretical physics of charge generation, transportation, accumulation, and relaxation. Laboratory experiments are simulating the physical processes operating in high-voltage transformers. *Project Manager: Dennis Johnson*

Improved static VAR compensation controls

Several utilities have applied SVCs to their systems in recent years. The technologies used for these applications were primarily extensions of the arc-furnace applications of the previous decade. Among the new considerations associated with utility applications is the need to design controls for wide variations in ac system strength and the distorted waveshapes associated with weak ac systems. The industry has dealt with these aspects on a case-by-case basis. A solid foundation for control design must be developed to ensure optimal performance on the utility system. The first two tasks of this project are directed toward developing such a foundation and exploring a wide variety of options for achieving optimal performance (RP2707-1).

SVCs are inherently capable of enhancing aspects of system performance beyond simply regulating average three-phase voltage magnitude, which is where they have been applied in most cases. The additional enhancements can be investigated once the basic foundations for voltage control are established. Using the individual-phase control capability to improve transient performance during unbalanced ac system disturbances is one aspect that this project addresses. SVCs can also have a major positive influence on damping power swing oscillations between remote generators and their load centers and between large areas. The design of special modulation controls to enhance power-swing damping is another subject of this project, as well as extension of concepts to include SVC applications in conjunction with an HVDC system. The focus of this effort is to demonstrate the capabilities of the SVC in enhancing these aspects of performance and to communicate the concepts to the utility industry. The contractor, General Electric Co., plans to work closely with one or more utilities in this effort, with the result being a set of guidelines by which system planners can readily use their stability programs to determine the potential benefits of SVC applications. *Project Manager: John Marks*

POWER SYSTEM PLANNING AND OPERATIONS

HVDC links in large systems

Multiterminal HVDC systems have recently become more viable because of the development of a dc circuit breaker. The objective of this project was to investigate the application of multiterminal dc links, multiterminal dc network analysis, the development of multiterminal dc controls, and control strategies (RP1964-2). Models of the dc controls will be incorporated in an EPRI-developed large-scale load flow and stability effort (RP1208).

The project has developed a flexible approach to model multiterminal dc systems and the associated controls. The flexibility extends from network modeling, where the dc network is built up from converter and line models, to a central scheduler modeling for obtaining a steady-state solution. A significant contribution of the project is the development of an extremely powerful control modeling capability—user defined controls (UDC)—that is incorporated into the ac/dc stability program. The UDC capability is provided through a comprehensive set of control system blocks, which can be connected together in any desired configuration to model any type of HVDC control.

The effectiveness of different HVDC control strategies and the capabilities of ac/dc load flow and stability programs were evaluated through the simulated responses of a large-scale test system (1500-bus size) for ac and dc faults.

The ac/dc load flow and stability program (MTDC) was tested for validation by New England Electric System and Manitoba Hydro, and it is now available through the Electric Power Software Center. *Project Manager: Neal Balu*

R&D Status Report
ENERGY ANALYSIS AND ENVIRONMENT DIVISION

René Malès, Vice President

LAKE-WATERSHED ACIDIFICATION: RILWAS

Over the last several years, EPRI has been active in testing and applying the results of the integrated lake-watershed acidification study, or ILWAS (RP1109), in different regions of the country. The general name given to this follow-on program is the regional integrated lake-watershed acidification study, or RILWAS (RP2174). The research has been done in cooperation with many utilities and utility organizations: Southern California Edison Co. in the Sierra Nevada, Northern States Power Co. in northern Minnesota, Wisconsin utilities in the northern part of that state, Utah Power & Light Co. in Utah, the Tennessee Valley Authority in the southern Appalachians, and Empire State Electric Energy Research Corp. in the Adirondacks. Various federal and state government agencies—including the U.S. Environmental Protection Agency, the U.S. Forest Service, the U.S. Geological Survey, the U.S. National Park Service, the California Air Resources Board, and the Wisconsin Department of Natural Resources—have also worked closely with EPRI in these efforts.

ILWAS developed a general mechanistic theory of surface water acidification. This theory, which takes the form of a mathematical simulation model, quantitatively relates the acid-base status of lakes and streams to the acidity of atmospheric deposition, taking into account the production and consumption of acidity by lake-watershed processes.

The ILWAS model was developed from an intensive study of three forested watersheds in the Adirondack Park region of New York. It has been assumed to be applicable to all lake watersheds, both in the Adirondacks and in other regions, because it was formulated by using fundamental mechanistic biogeochemical concepts. In 1982 RILWAS was started to verify the major ILWAS conclusions and to test, and if necessary enhance, the general applicability of the ILWAS model. This follow-on work was to use the ILWAS approach and model to analyze the acid-base dynamics of 25 additional sites in the Adirondacks, as well as sites in other regions of the United States. This status report summarizes the results for a major subset of the Adirondack RILWAS sites—16 interconnected sites in the basin of the North Branch of the Moose River (also referred to as the Big Moose Basin). These sites, shown in Figure 1, are located near the ILWAS lakes.

Three principal technical factors led to the selection of the Big Moose Basin as a RILWAS study area. One was the spatial variation of the chemical characteristics of surface waters within the basin. There is a general pattern of increasing alkalinity and pH as one proceeds downstream from north to south, with a dramatic contrast in acid-base status between the subcatchment north of Big Moose Lake and the subcatchment east of Lake Rondaxe. Furthermore, there are the anomalies of Windfall Pond, which is an alkaline lake in the middle of an acidic subregion, and West Pond, whose sulfate concentration is low relative to that in the rest of the basin. The spatial (and also temporal) variation of surface water quality in the Big Moose Basin provided a robust test of the analytic capabilities of the ILWAS acidification theory.

The second factor in the selection of this

Figure 1 Basin of the North Branch of the Moose River. The results of research at the 16 RILWAS sites shown here support the surface water acidification theory developed in ILWAS.

area was the interconnectedness of the lakes. RILWAS was designed to address an issue not covered in ILWAS—the correlation between the distribution of fish species and the acid-base status of lakes. The lakes in the Big Moose Basin, which are highly varied in acid-base status and have no physical barriers to prevent fish movement from one lake to another, provided an excellent system for conducting such an analysis.

The third factor favoring selection of the Big Moose Basin was the availability of considerable historical information on the water chemistry, distribution of fish species, and land use in the area. This information facilitates the paleoecological analysis of historical lake acidity and the assessment of historical changes in fisheries.

Verifying the ILWAS conclusions

Last year the international science journal *Water, Air, and Soil Pollution* devoted an entire issue (Vol. 26, No. 4) to summary papers from ILWAS. Major conclusions of the study follow.

- The acid-base status of lakes depends on the interaction of many factors: vegetation, soil, hydrology, geology, climate, limnology, and atmospheric deposition.

- The absolute and relative contribution of any single factor can vary greatly from watershed to watershed and over time.

- The response of lakes to changes in the chemical composition of atmospheric deposition can vary greatly from watershed to watershed and over time.

- In general, the role of an individual factor in determining the acid-base status of a lake or the response of a lake to changes in deposition chemistry can be understood only within an integrated ecosystem framework.

- The route water takes through a watershed is a major determinant of a lake's alkalinity (acid-neutralizing capacity) and its vulnerability to acidification by atmospheric deposition.

- Alkalinity is a key variable for characterizing the acid-base status of surface waters.

- To understand the acid-base status and dynamics of surface waters, it is necessary to understand the processes that regulate the aqueous concentrations of all major cations and anions (organic and inorganic).

The intraannual fluctuations of surface water chemistry observed in the Big Moose Basin support the major conclusions of ILWAS and the conceptual basis of the ILWAS model. With one exception, the acidity production and consumption processes observed in the basin were included in the original version of the ILWAS simulation model. The exception is the loss of strong acid anions by reduction reactions in sediments and soil. This process can represent a significant source of alkalinity—for example, in West Pond and in summer flow in Pancake Hall Creek.

There was no appreciable reduction of sulfur in the ILWAS lakes because of the short mean residence time (less than seven months) of water in the lakes. The rate of diffusion of sulfate from lake water into sediments appears to be a key factor in controlling the extent of sulfate reduction. The removal of a significant amount of sulfate from the entire water volume can occur only if the water resides in the lake long enough to allow the sulfate to diffuse into the sediments, where reduction occurs. The ILWAS model has been modified to cover the diffusion of sulfate into sediments and its subsequent reduction.

ILWAS pointed out the futility of trying to identify a single factor that in general determines the acid-base status of lakes. This conclusion is supported by analyses of the Big Moose Basin, which could not correlate lake acid-base status with the frequency distribution of instantaneous water discharge, the distribution of tree communities, or soil depth.

Although soil depth was an excellent single index for differentiating among the three ILWAS lakes in terms of acid-base status, the ILWAS researchers cautioned that in general soil depth should not be expected to be an accurate indicator; and indeed, it failed for the Big Moose Basin, a relatively small area (136 km^2) in the same general region of the Adirondacks as the ILWAS lakes. One reason for this failure is the occurrence of significant sulfate reduction in sediments (e.g., at West Pond). Another is the presence of significant quantities of carbonate-bearing calcsilicate rock in the watershed (e.g., at Windfall Pond). The extreme variation in the spatial distribution of this rock supports the second and third ILWAS conclusions listed above and demonstrates the potential difficulty of basing a regional assessment on analyses of a few watersheds.

The Big Moose Basin results strongly support the ILWAS conclusion regarding the importance of flow path analysis. Because of flow path considerations, it is important to know how watershed properties (e.g., soil depth) are spatially distributed throughout a basin. If a potential source of alkalinity is not in an area that is a major source of flow to a lake, then its ability to contribute alkalinity to the lake will be limited.

Fish species distribution

The fish research undertaken in RILWAS has shown watershed acidity gradients and relative physiological acid tolerance to be major determinants of fish species distribution in the Big Moose Basin. Since 1931 the range of less-acid-tolerant fish species in the basin has decreased, with the species disappearing from the more acid regions of the basin. Analyses of diatom and chrysophyte stratigraphies indicate an acidification of Big Moose Lake from pH values near 6 to about 5. This acidification has taken place during the same period in which the spatial distribution of the fish species has been decreasing.

Higher sulfur concentrations are found in the upper part of sediment cores from Big Moose Lake, which implies increased sulfur deposition to the sediments over the last several decades. Unfortunately, because of the mobility of sulfur in sediments, sulfur deposition cannot be quantified and dated as accurately or precisely as diatom deposition. (Paleoecology is one of the few scientific fields in which the interpretation of biologic data appears to be more accurate than that of chemical data.)

In summary, there is evidence to correlate increased sulfur deposition to the sediments of Big Moose Lake with the acidification of the lake and the disappearance of acid-sensitive fish species.

Regional assessment

As with ILWAS, the findings for the Big Moose Basin cannot be broadly interpreted as an assessment for the entire Adirondack region, especially in light of the large spatial variation in biogeochemical and hydrologic characteristics they reveal. The question is how representative of the Adirondacks are the various subcatchments and the various lakes and streams within the basin. An integrated analysis of the entire set of RILWAS Adirondack sites is expected to produce a classification scheme for the sensitivity of Adirondack lake watersheds to changes in the chemical composition of atmospheric deposition. A regional assessment for the Adirondacks could then be developed by applying this classification scheme to the entire area.

One of the chief advantages of the ILWAS model over other acidification models is its completeness: it simulates all known significant acidity production and consumption processes and the behavior of all major cations and anions. Although not all processes or ions may be relevant in a given implementation, there is no need to create simpler models for particular situations because the time required for an integrated simulation of all processes is short. The model's fast execution time will also facilitate broader geographic assessments.

By demonstrating the robustness of the lake-watershed acidification theory developed in ILWAS, the Big Moose Basin case study analysis indicates that the ILWAS model should be applicable to other regions as well as to the Adirondacks. This finding is consistent with those of all other applications of the ILWAS model to date. *Project Manager: Robert A. Goldstein*

INTEGRATED FOREST STUDY

*Reports of forest decline in Europe and North America have attracted considerable attention from governments, scientists, and the public (*EPRI Journal, *September 1985, p. 16). Some scientists have suggested that acidic deposition can have detrimental effects on forests and could lead to forest decline. During 1985 EPRI initiated a major investigation that will address this important issue—the integrated forest study on effects of atmospheric deposition (RP2621). Its key objective is to understand the short- and long-term effects of atmospheric deposition on the mineral nutrient status of various forest ecosystems. EPRI has been joined by the Empire State Electric Energy Research Corp. and Southern Company Services, Inc., in supporting this effort. Also, the National Acid Precipitation Assessment Program (NAPAP) recently decided to participate in the project and will independently fund two additional sites. Scientists in the Environmental Sciences Division at Oak Ridge National Laboratory (ORNL) are responsible for coordinating the four-year study.*

Forests are complex, long-lived systems that typically respond slowly and in subtle ways to environmental perturbations. Atmospheric deposition is a complex phenomenon that might affect forests through many different mechanisms, both direct and indirect. It is not surprising that many hypotheses have been proposed to explain how atmospheric deposition could cause forest decline. In addressing the question of how atmospheric deposition might affect forest nutrient status, the integrated forest study (IFS) focuses on perhaps the most fundamental and significant type of potential effect. The study will also provide results relevant to hypotheses that include or assume other effects on soil chemistry or plant nutrient status.

The IFS is an ecosystem-level study of processes of nutrient transfer that link the atmosphere, living vegetation, soil, and soil water. For each forest site, investigators will describe the biogeochemical cycles of all major cations and anions (H^+, Ca^{++}, NH_4^+, Mg^{++}, K^+, Al^{+++}, Na^+, NO_3^-, SO_4^{--}, HCO_3^-, Cl^-, PO_4^{--}, and, indirectly, organic acid anions). That task will involve measuring the mineral content of major ecosystem components (overstory vegetation, understory vegetation, litter, and soil) and monitoring the annual flux of minerals within the ecosystem (input through wet and dry deposition, canopy interactions, litter fall, plant uptake, movement through the soil, and leaching from the system). Biogeochemical studies of nutrient cycling have been conducted in the past, but never on the scale of the IFS. The goal of the study is to quantify important deposition and mineral-cycling processes in greater detail than has been previously attempted.

Another IFS goal is to provide information that is not site-specific and that can eventually be used to address general questions concerning the effects of atmospheric deposition on forests. One approach would have been to conduct experiments on replicate study plots in one or a few areas. Instead, the ORNL and university scientists proposed a comparative study in which they will evaluate mineral cycling under natural conditions in a range of forests differing in a number of ways. Because the same instruments and methods of analysis are being used at many sites, the results will be more comparable than if each site were part of an independent study.

At the end of the study, it will be possible to relate variations in nutrient status to differences in deposition rates, vegetation, or soil. Because all the important known processes in deposition and nutrient cycling will be quantified, it should also be possible to identify which processes play key roles in regulating the effects of atmospheric deposition and to assess how sensitive these processes are to changes in the deposition regime. Thus the results will be more than mere correlations between deposition regime, environmental characteristics, and nutrient status.

Site selection

The current IFS sites (Table 1) were chosen on the basis of several criteria. Most important, the sites differ in climate, vegetation, and deposition regime. In particular, they differ in the levels of loading of H^+, SO_4^{--}, and NO_3^-.

Especially interesting in this regard is the Thompson Forest site in Washington, where study plots have been set up in both Douglas fir and red alder stands. Ambient levels of acidic deposition are low compared with levels at eastern sites, and in some respects the Douglas fir plots represent an experimental control in terms of acidic deposition. The red alder plots, in contrast, are naturally acidified sites with very high levels of NO_3^-. The nitrogen-fixing bacteria associated with red alder roots convert atmospheric nitrogen gas to organic nitrogen compounds. As a result, ammonium levels build up in the soil to the point where unusually high rates of nitrification occur (microbial conversion of NH_4^+ to NO_3^- and H^+). By generating H^+ this process acidifies the soil rapidly. The changes occurring in the soil after red alder becomes established may be similar to those that could result from a large anthropogenic input of H^+ and NO_3^-.

Sites in the Northeast (Huntington Forest and Whiteface Mountain) were selected because concern over the effects of acidic deposition has focused on that area. Similarly, two mountain spruce-fir sites (the Whiteface Mountain and Smoky Mountain sites) were chosen because it is widely believed that any effects will first be observed in high-elevation locations that are already naturally stressed and are heavily exposed to atmospheric deposition, especially from cloud immersion. The large number of sites in the Southeast reflects the growing concern over the health of commercially important forests there. The three loblolly pine sites (in Tennessee, North Carolina, and Georgia) come close to encompassing the broad range of conditions under which that important timber species grows. Other sites represent additional variants of vegetation, climate, and deposition regime.

Other criteria important in site selection included the availability of trained scientists and the availability of electricity for the meteorologic and deposition-monitoring instruments. Also, the IFS sought sites where related work had already been conducted. For example, work conducted at Oak Ridge under previous EPRI contracts (RP1813, RP1907) was important in the development of this project. The Norwegian site also takes advantage of previous experimental work and provides tree species and an environment not covered by the other IFS sites.

Several cooperating sites have been recently added to the project or will be added in the near future. The Canadian Forest Service, through its Great Lakes Research Centre, has agreed to sponsor a site; its investigators will follow the IFS protocols and participate fully in the project. The same arrangement has been made for the two federally funded NAPAP sites, which will probably be located in a commercial spruce-fir forest in Maine and in a slash pine forest on the coastal plain of Florida or Texas.

Experimental tasks

Although the main focus of the IFS is on monitoring deposition and nutrient cycling at a variety of field sites, several experimental tasks support this monitoring work. One group of experiments will supplement the atmospheric deposition monitoring by providing estimates of certain components of deposition that cannot easily be measured at all field sites. A study using the natural isotopes lead-212 and beryllium-7 will evaluate the deposition of submicrometer particles to vegetation and improve the quantification of aerosols as a sulfur source to ecosystems. A study at the Cary Arboretum in New York state will experimentally investigate the extent to which nutrient leaching and cation exchange occur at leaf surfaces in the canopy. In addition, the importance of HNO_3 gas as a component of dry deposition

Table 1
CURRENT IFS SITES

Location	Forest Type	Elevation (m)	Contractor
Thompson Forest and Findley Lake, Wash.	Douglas fir–red alder Fir-hemlock*	100 1100	University of Washington
Huntington Forest, N.Y.	Mixed deciduous	530	State University of New York at Syracuse
Whiteface Mountain, N.Y.	Spruce-fir	1000–1500	University of Pennsylvania, State University of New York at Albany
Great Smoky Mountain National Park, N.C. and Tenn.	Spruce-fir Beech*	1800 1800	Oak Ridge National Laboratory, U.S. National Park Service
Coweeta Hydrologic Laboratory, N.C.	White pine Mixed deciduous*	800–1100 700–1000	U.S. Forest Service
Oak Ridge, Tenn.	Loblolly pine	300	Oak Ridge National Laboratory
Duke Forest, N.C.	Loblolly pine	215	Duke University
Grant Forest, Ga.	Loblolly pine	175	Emory University, University of Georgia
Nordmoen, Norway	Norway spruce	200	Norwegian Forest Research Institute
Turkey Lakes, Ontario, Canada	Sugar maple–birch	350	Canadian Forest Service

*Sites without intensive deposition monitoring.

will be evaluated in controlled chamber studies. These experimental tasks are not being undertaken at all sites, but the results will contribute to an improved understanding of deposition processes.

A set of experimental tasks also complements the nutrient-cycling work being conducted at each field site. The hypotheses to be tested are important for interpreting results from the monitoring work and for projecting the effects of atmospheric deposition. In these experiments researchers will assess the relative importance of organic versus inorganic sulfur accumulation in regulating nutrient leaching from soils, will assess the potential for mitigating soil acidification by changing the species composition of a forest, and will measure the efficiency with which H^+ ions replace important base cations (e.g., Ca^{++} and Mg^{++}) in the soil. A recently added experimental task will focus on the critical question of whether the process of soil weathering (the chemical breakdown of rock minerals in soil) can replenish cations that have been leached as a result of acid inputs.

Current activities

In the latter part of 1985 and the early part of 1986, IFS investigators prepared the field sites. All the original sites were fully operational by the beginning of the 1986 growing season.

At each field site all work is focusing on one or more 0.1-ha plots. The number of plots depends primarily on the spatial variation in the vegetation. Within each plot the nutrient content of each component of the ecosystem must be measured at the outset of the study and again at the conclusion. Foliage, branch, bole, and root samples must be collected from all major overstory and understory species. Samples of litter and soil (at different depths) must also be collected and analyzed for nutrient content. After all these analyses are completed, it will be possible to calculate total standing pools of all major anions and cations in the study plots.

The nutrient-cycling work also involves calculating the annual flux of minerals between ecosystem components. This is done primarily by monitoring the chemical content of water as it moves through the ecosystem. In each plot, replicate sampling devices have been set up to monitor throughfall (precipitation dropping from the canopy). The chemistry of throughfall is a function of the rain's composition and of any interactions with leaf or branch surfaces. Samplers have also been installed on trees to collect stemflow—the solutions that run down the branches and trunk to the soil surface. It is important to measure stemflow, as distinct from throughfall or bulk precipitation, because it can represent a significant volume and can pick up various chemicals as it flows down the branches.

Perhaps the most challenging aspect of monitoring mineral fluxes involves the movement of the minerals in the soil. Lysimeters placed at various soil depths are collecting samples of soil water for analysis of its chemical composition.

The other part of the monitoring work involves measuring wet and dry deposition and collecting related meteorologic data. This is a challenging task because of the complex nature of atmospheric deposition and also because of the specific problems involved in measuring deposition to complex, uneven forest canopies. Much of the equipment for this work is mounted on a meteorologic tower extending 16 ft (5 m) above the canopy. The following equipment has been installed at each site: a standard meteorologic package, a dry deposition collector, a particle and vapor filter pack and vacuum pumps (for measuring concentrations of various gases and vapors), a fog/cloud water collector, an ozone monitor, wet-only precipitation and throughfall collectors, a recording rain gage, and a data logger.

With all this equipment, wet and dry deposition will be measured with a thoroughness and accuracy never before achieved as part of a comprehensive nutrient-cycling study. Because of the difficulties in measuring deposition to forests, various components of deposition will be measured by more than one method so that the results can be compared.

The goal of the monitoring work is to collect three years of data on deposition and nutrient cycling. At the end of each full year of operation, annual nutrient flux budgets will be calculated for each site. As the study progresses, these interim results will be integrated with data from the experimental tasks to determine if and where any modifications in the project are warranted. At the project's conclusion, it should be possible to answer a variety of questions about the nutrient status of the forests at the various sites, including the following. Are nutrients being progressively lost from certain forest sites, and if so, at what rate? To what extent does soil weathering compensate for the loss of minerals? Are higher rates of leaching related to the level of atmospheric deposition at the site, and if so, what specific processes or steps in the cycling of nutrients are affected? How important is leaching or ion exchange in the canopy, and how does this vary with vegetation type? How does variation in the amount of wet versus dry deposition alter the effects of deposition? Are there easily measured properties of vegetation or soil that can be used to predict the sensitivity of an ecosystem to acidification or nutrient leaching? *Project Manager: Louis Pitelka*

R&D Status Report
ENERGY MANAGEMENT AND UTILIZATION DIVISION

Fritz Kalhammer, Vice President

METHODOLOGY FOR ASSESSING ENERGY PARKS

Energy parks—which feature integrated supply systems for providing electrical and thermal energy to industries, businesses, and even residences—offer the potential for meeting total energy needs more efficiently and economically than do conventional approaches. EPRI-sponsored research has addressed the energy park development process and has produced a useful analytic tool for assessing project feasibility (RP1276-18, -26). This methodology has been successfully applied to three distinctly different utility sites. Research now under way is developing an assessment guide and a software package to enable utility planners to make direct use of the methodology.

Potential benefits

An energy-integrated industrial park, or energy park, is a facility that meets all the electrical and thermal needs (e.g., electric power, space heating and cooling, process heat) of one or more users from an integrated energy supply system. These systems, which employ such concepts as cogeneration and waste heat recovery, may involve existing utility power stations and/or new on-site facilities and may burn traditional fuels and/or unconventional fuels (e.g., biomass, waste streams).

An energy park project can be viewed as a mini–utility system that supplies both electric power and heat to a defined area. Potential project sites can range from undeveloped to fully occupied. Park occupants can include residential, commercial, and institutional energy users, as well as industrial. The owner-developer can be the local utility, a major energy user, or a third-party investor. Typically an energy park project is jointly owned by equity partners, such as the local utility (or its subsidiary) and one or more third-party developers, with attractive benefits for all participants.

Utility interest in developing energy parks is increasing for a variety of reasons. Energy parks can provide opportunities for obtaining generating capacity at reduced capital cost; increasing the use of underutilized capacity by refurbishing or retrofitting units to supply thermal energy as well as electricity; protecting and expanding the traditional customer base by diversifying into new, and possibly unregulated, business areas; and demonstrating corporate citizenship by promoting economic development.

Energy users (the park occupants) stand to benefit from a reliable energy supply at lower cost than traditional sources; this advantage could be extended to small as well as large users without requiring large capital investments or special engineering expertise on their part. Project owners and developers can expect favorable returns on investment. The community at large could benefit from enhanced economic development, from decentralized power generation with reduced environmental impact, and from a reduced solid-waste burden as the result of a waste-to-energy facility. (Of course, an attractively priced, integrated energy supply—the unique feature of energy parks—is only one of many factors involved in promoting community economic development; others are low real estate costs, access to cheap and abundant raw materials, availability of a large labor pool, favorable tax treatment and project financing, and proximity to markets or related business centers.)

Feasibility assessment

How can promising opportunities for energy parks be identified? Over the past two years, an EPRI-sponsored research effort by Burns & McDonnell Engineering Co. and the United Technologies Research Center has developed a methodology for screening and evaluating energy park project options. The methodology will help utilities answer three basic questions.

The first question addresses technical feasibility: is there a practical energy supply system configuration to meet the park's projected requirements? The second addresses economic feasibility: can this configuration provide energy at a competitive price while yielding an acceptable rate of return to investors? The third addresses institutional feasibility: can all the financing, market, regulatory, environmental, and community issues be dealt with satisfactorily?

Energy park projects are inherently complex, involving many parameters and choices. They are also highly site-specific; no two projects are alike. Although a detailed specification is not necessary during the early planning phases, a decision to proceed requires that the key project elements and technical and economic parameters be known with sufficient confidence to confirm preliminary feasibility. Major uncertainties must also be investigated to determine their effect on project feasibility and overall business risk.

In response to these needs, the EPRI contractors have produced a methodology that can be used to evaluate the feasibility of a specific energy park project or to perform a technical and economic screening of a large number of project options. The methodology comprises seven steps.

▫ Assess site feasibility. In this first step promising candidate sites are identified, their physical features and institutional constraints are characterized, and the candidates are ranked.

▫ Establish site development strategy. A plan specifying the expected or desired occupant mix and the land development schedule is drawn up for each selected site.

▫ Forecast energy demand. On the basis of the site development plan, the aggregate electrical and thermal loads of the park occupants are estimated for each year of project development.

▫ Identify applicable energy technologies. A large variety of candidate fuels and energy supply systems are screened to identify those most appropriate for the proposed project.

▫ Assemble energy supply systems. One or more technically feasible configurations satisfying the park's energy needs are devised, and the capacity mix, capacity addition schedule, and annual operating strategy are defined for each.

□ Evaluate project economics. The economic and financial performance of proposed project options is determined and compared with the goals of the project participants.

□ Assess overall project feasibility. The technical, economic, and institutional factors are integrated, optimized, and evaluated to determine the project's feasibility and the risks it entails.

Case studies

Three case studies involving actual utility sites have been conducted to demonstrate the usefulness of the methodology. In each case the researchers have characterized physical site features, existing energy facilities, and institutional issues; developed over 100 supply system configurations; and evaluated the most promising project options by using generic screening criteria, site-specific constraints, and the particular objectives of the utility/developer. The studies, which are documented in EPRI EM-4581 (4 vols.), illustrate the diversity of potential energy park projects.

The first case study involves a 225-acre (91-ha) undeveloped site in Chesterfield, Virginia, about 10 miles (16 km) south of Richmond. Lying adjacent to the six-unit Chesterfield station of Virginia Power, the site is zoned for heavy industrial use; the target occupants are energy-intensive process industries. The project is assumed to be wholly owned by the utility, whose primary goals are to make maximum use of existing energy facilities and to achieve an acceptable rate of return.

The selected supply configuration calls for modifications to three of the existing coal-fired Chesterfield units to provide extraction steam to the park, with oil-fired auxiliary boilers for backup and peaking. The estimated capital investment for this configuration is approximately $8 million. (All figures are in 1984 dollars.) It is concluded that the project could achieve the target discounted after-tax rate of return of 10% and provide thermal energy to park occupants at a first-year price of $5.50 per million Btu.

The second case study involves a 650-acre (263-ha) site in Marley Neck, Maryland, 10 miles (16 km) southeast of Baltimore. The site is near two Baltimore Gas & Electric Co. power plants—the three-unit Wagner station and the new two-unit Brandon Shores station. It is currently used for ash fill. A wholly owned utility subsidiary has been established to develop the site as a combination business-industrial complex. The project would be jointly owned by the utility and its subsidiary.

A key feature of this site is the availability of both corporate solid waste and municipal sewage sludge—a unique low-cost fuel source that the project could take advantage of while helping to ease a critical waste burden on the community. It is expected that the project would receive a fee for disposing of these waste streams in a waste-to-energy facility. The selected energy supply configuration features extraction steam provided by the utility from the existing power stations, additional electricity and hot water provided by the utility subsidiary from two 35-t/d solid-waste cogenerators, and oil/gas-fired packaged boilers for backup and peaking.

The estimated capital investment for this configuration is about $8 million for the utility-owned portion and about $20 million for the portion owned by the utility subsidiary. Economic results indicate that both parties can obtain a favorable rate of return: the utility can provide power station extraction steam to its subsidiary at a first-year price of $5 per million Btu and achieve its target discounted after-tax rate of return of 7.5%, and the subsidiary can provide thermal energy to the park occupants at a first-year price of $6.50 per million Btu with a rate of return over 15%.

The third case study involves two alternative sites in Ontario, California, about 35 miles (56 km) east of Los Angeles: a 1500-acre (610-ha) site adjacent to the Etiwanda power station of Southern California Edison Co. and a 2500-acre (1010-ha) site located approximately 2 miles (3.2 km) away. Each site is currently being marketed by third-party developers as a business-commerce center, and each is partially occupied, primarily by warehouse facilities serving the nearby Ontario Airport.

Different development approaches were used for the two sites. For the first a supply-side-driven approach was taken, in which the capabilities of the nearby power station define the size and nature of the energy demand to be served by the park. The selected supply configuration calls for extraction steam from the Etiwanda station (backed up by gas-fired packaged boilers) to serve approximately two-thirds of the 1500-acre site. For the second site a demand-side-driven approach was taken, in which the site's projected energy requirements determine the size and nature of the energy supply system. The selected configuration for this project features four new gas-fired combined-cycle cogenerators (with gas-fired packaged boilers for backup) located on site to serve the entire 2500 acres.

The economic results for each configuration are as follows. For the 1500-acre site, the estimated capital investment is $75 million, and a rate of return above the target 9% is achievable for a first-year steam price of $6 per million Btu and a first-year electricity price of 5.6¢/kWh. For the 2500-acre site, the estimated capital investment is $120 million, and the expected rate of return is in the 15–20% range for a first-year steam price of $6–$8 per million Btu. In each instance the proposed park is expected to provide energy to park occupants at a competitive price while meeting the project owners' required financial return.

Assessment tools

Feasibility assessment of an energy park project is comparable to the load forecasting and generation planning studies conducted by the utility industry, with the addition of the thermal component. Screening project options and assessing feasibility can be made easier by relying on past experience and rules of thumb.

In a followup effort the United Technologies Research Center is refining the screening methodology and preparing user-friendly analytic tools for direct use by utility planners: an energy park assessment guide, an IBM PC–compatible software package, and an evaluation procedures/users manual. These tools are intended to provide a framework for characterizing key features of an energy park project; guidelines for selecting promising energy supply configurations, determining overall project feasibility, and assessing risk; and a detailed methodology for screening, evaluating, and optimizing a variety of project options.

A demonstration workshop was held in June 1986, and the energy park assessment guide and prototype software package are now available to interested utilities. *Project Manager: S. David Hu*

R&D Status Report
NUCLEAR POWER DIVISION

John J. Taylor, Vice President

ASME EVALUATION CRITERIA FOR PRESSURE–TEMPERATURE TRANSIENTS

Design studies of nuclear reactor pressure vessels include analyses of the effects of certain pressure and temperature transients to which it can be assumed the vessels will be subjected during their operating lifetimes. However, pressure and temperature transients sometimes occur that exceed limits defined in the plant technical specifications. These unanticipated transients usually cause the plant to be shut down until the utility or the reactor vendor can make a detailed analysis to demonstrate adequate structural integrity.

The prevention of brittle fracture of reactor pressure-retaining components is essential to the safe operation of nuclear power plants. Pressure and temperature operating limits are established in accordance with the ASME Code, Section III, Appendix G, which defines margins of safety for plant operation. These pressure and temperature operating limits are contained in the plant technical specifications, as required by the Code of Federal Regulations, Part 50 (10 CFR 50), Appendix G, which mandates the ASME Code procedures. A different pressure-temperature limit curve is included for each of several conditions, including plant heat-up, cooldown, core criticality, and pressure testing. These curves must be updated as is necessary to account for the effects of neutron fluence on the material toughness.

Any event, even an inadvertent violation, that exceeds these technical specification limits must be reported to NRC. In addition, an engineering evaluation must be performed following the event to determine its effects on the structural integrity of the reactor coolant system as the basis for justifying plant restart.

In the past, the effects of such incidents on reactor vessel integrity have been analyzed on a plant-specific basis because there were no guidelines for making the analyses. An alternative procedure for evaluating the effects of a pressure-temperature transient on reactor vessel integrity has recently been approved by the ASME Code and endorsed by NRC. The evaluation criteria were developed in an EPRI project (RP1757-41) and applied through the ASME Section XI Special Working Group on Operating Plant Criteria. The result of this work is Nonmandatory Appendix E to Section XI of the ASME Code for Analytical Evaluation of Plant Operating Events. This appendix will appear in the Winter 1986 Addenda to the ASME Code.

Evaluating the effects of transients

Much of the concern regarding pressurized thermal shock (PTS) events has been about quantifying the margins of safety during a PTS transient. Of greatest concern are the older nuclear plants, in which the vessels are more highly embrittled from neutron irradiation (Figure 1). This new appendix to the ASME Code eliminates the need for detailed plant-specific analyses following most PTS events or overpressurization transients. Screening criteria are established whereby transients not exceeding the limits of these criteria are shown to be acceptable for returning the reactor vessel to service without making further analyses of the vessel beltline. Because the beltline is the vessel region that is most sensitive to embrittlement, the post-transient evaluation can be performed quite readily.

As an example, for pressurized thermal transient events during which the cooldown rate exceeds 10°F/h (6°C/h), the Appendix E criteria are satisfied if the maximum pressure does not exceed the design pressure and if $T_c - RT_{NDT}$ is not less than 55°F (13°C), where T_c is the lowest bulk reactor coolant temperature during the transient, and RT_{NDT} is the highest adjusted reference temperature (for weld or base material) at the inside surface of the reactor vessel. This reference temperature is an index of reactor vessel toughness, and the effects of neutron embrittlement are determined by NRC Regulatory Guide 1.99, Rev. 2, "Radiation Damage to Reactor Vessel Materials."

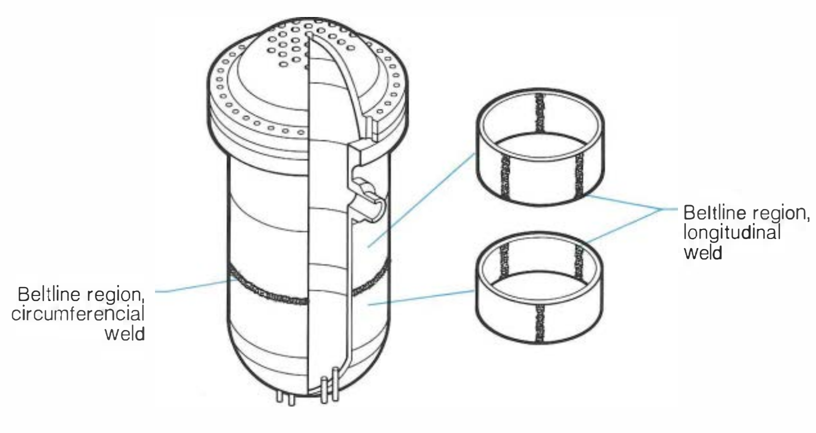


Figure 1 Following exposure to an out-of-limit pressure or temperature transient, it is essential to plant safety that the structural integrity of the pressure vessel be verified. The longitudinal and circumferential welds in the beltline region of the pressure vessel are critical points. Particularly in older vessels, these areas may be more sensitive to radiation-induced embrittlement because of higher concentrations of copper and nickel in the welds.

The guidelines for Appendix E are based on the methods of linear elastic fracture mechanics (LEFM). The Appendix E criteria were developed to ensure a margin against crack initiation for postulated flaws in the vessel wall with depths up to 1 in (25 mm). The crack size range was assumed to have an upper limit of 1 in because experience shows that the fabrication practice and inspection requirements for nuclear pressure vessels generally preclude the possibility of larger flaws having been undetected. A significant number of hypothetical cooldown transients were chosen for evaluation by using LEFM techniques and applying these methods. Representative fracture toughness values for the vessel materials were used, together with appropriate safety factors to prevent brittle crack initiation. The resultant screening criteria were determined to be conservative and independent of the cooldown rate for evaluation of overcooling transients. A similar study was performed to develop the Appendix E criteria for low-temperature overpressurization events.

For those events not meeting these simplified criteria, Appendix E includes generalized fracture mechanics evaluation guidelines for detailed assessment of vessel integrity following a reactor transient. In performing such an analysis, the actual pressure and temperature time histories are to be used, as well as the initiation fracture toughness for vessel steels, K_{IC}, which is designated in the code as a function of metal temperature. Acceptable margins of safety are defined as applied to the stress intensity factors from membrane stress, thermal stress, and residual stress calculated throughout the plant transient. Analyses performed in accordance with these guidelines that meet the specified criteria are shown to be acceptable for continued safe operation of the vessel.

The benefits of Appendix E to the utilities are significant. For most unanticipated transients, the utility will be able to perform the required evaluation within hours to demonstrate that the structural integrity of the reactor vessel beltline is adequate for the vessel's return to service. Also, NRC can have confidence in restart decisions based on results of the method's application because the criteria are now part of the ASME Code. As a result, many days or weeks of plant downtime can be avoided.

Using the screening criteria

These evaluation criteria were first used in January 1986 following an overcooling event at the Rancho Seco plant on December 26, 1985. A loss of integrated control system power caused a reactor trip that cooled the vessel from 582°F to 386°F (306°C to 197°C) within 24 min, a significant violation of the technical specification requirements that the cooldown rate not exceed 100°F/h (56°C/h). EPRI was asked by the utility (Sacramento Municipal Utility District) to make an independent assessment of the effects of this transient on the integrity of the Rancho Seco vessel.

The ASME Code screening criteria from Appendix E were applied, and the analysis was completed in a matter of days. A conservative determination of the vessel RT_{NDT} was 217°F (103°C) at the vessel surface for the limiting weld material. The difference between the lowest transient temperature and the vessel RT_{NDT} was calculated to be 169°F (76°C), significantly greater than the 55°F (13°C) margin required by the screening criteria. The results demonstrated that adequate margin existed and that the vessel could be returned to service. The NRC study concurred with the EPRI analysis, and the issue of reactor vessel integrity was rapidly dismissed.

The screening criteria were again applied following a loss of shutdown cooling at the San Onofre-2 plant on March 26, 1986. In this case, a violation of the plant technical specifications resulted when a heat-up transient from 110°F to 212°F (43°C to 100°C) occurred in less than an hour, which exceeded the 100°F/h (56°C/h) heat-up rate limitation. Because the simplified screening criteria from Appendix E do not apply for overheating events, the utility (Southern California Edison Co.) did a fracture mechanics analysis by using the generalized guidelines and criteria of the new appendix. Stress intensities caused by heat-up stresses in the vessel were calculated and, together with the code-defined safety factors, were compared with the allowable fracture toughness. This fairly straightforward task was completed by the utility in a few days. The results demonstrated that brittle fracture of the vessel was not a concern in this transient event. Without the code-approved evaluation guidelines, such an analysis would have been much more difficult and time-consuming.

These applications indicate the kinds of unanticipated pressure-temperature transient that occur and have in the past repeatedly raised questions about reactor vessel integrity. The adequacy of reactor vessel toughness can now be demonstrated for most operating transients by using the new Appendix E to Section XI of the ASME Code. *Project Manager: T. J. Griesbach*

MODELING ULTRASONIC FLAW DETECTION

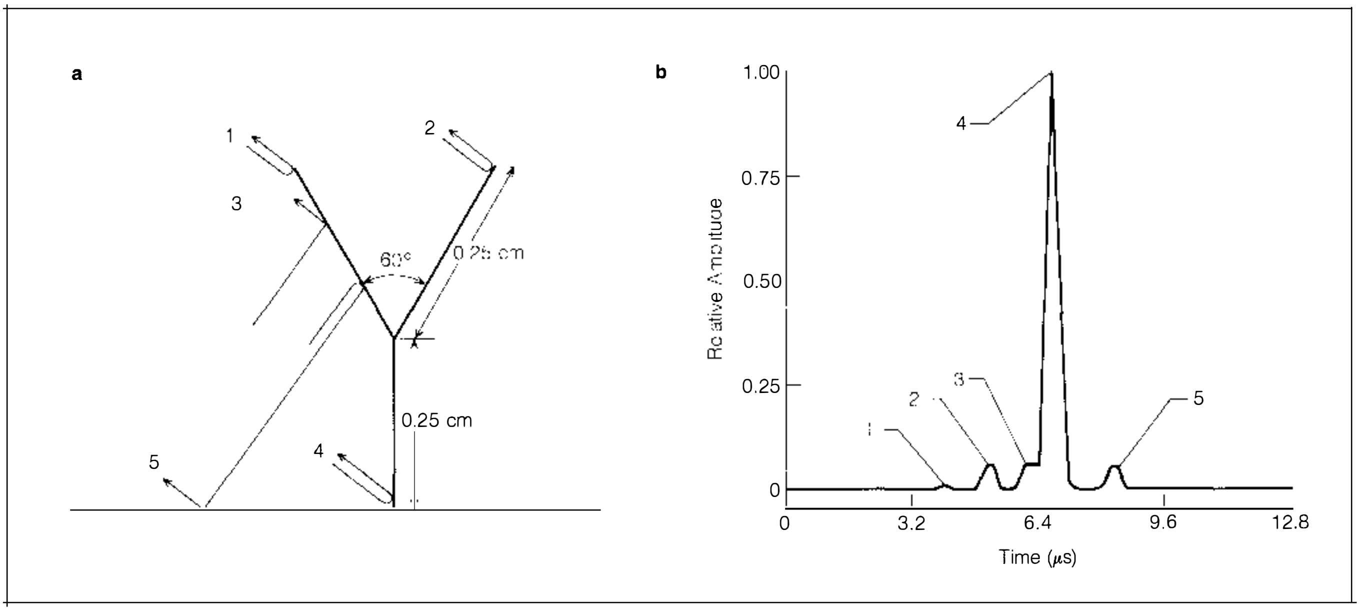
Ultrasonic testing (UT) is a nondestructive means of detecting structural abnormalities in pressure boundary components at nuclear power plants. In these tests, high-frequency sound waves are passed through the parts to be inspected. Waves that impinge on discontinuities within the material are reflected back to an instrument that displays them on a cathode-ray tube. Because the reflections, or echoes, are altered in various, characteristic ways by the surfaces from which they are reflected, they contain information that can be used to determine the location and size of any flaws. To a great extent, of course, the accuracy of UT depends on a proper interpretation of the recorded echoes. Unfortunately, the high reliability originally assumed for UT has not proved out in practice. Cracks that have gone undetected in ultrasonic inspections and cracks that have been detected but whose magnitudes have not been correctly assessed have resulted in large losses for some utilities. As a result, it is important that ways be found to improve UT reliability.

A search for the causes of the differences between expected and actual reliabilities of UT techniques disclosed a sparsity of theories and models appropriate to ultrasonic inspection as it is implemented today. Cracks are not simple ultrasonic reflectors, and they often occur in highly anisotropic, inhomogeneous materials. Pipe-to-pipe welds, weld overlaying, and pipe cladding are particularly difficult in terms of applying simplified theories of sound scattering. For example, in several techniques it is assumed that the amplitude of an echo is directly proportional to the size of the reflector that produced it. This simple relationship is sometimes true, but not always. The topography of cracks and their locations relative to other reflectors are proving to be major factors that influence echo characteristics.

An empirical approach to the problem of relating reflector and echo characteristics could be used, but it would involve accumulating experimental data and making a subsequent statistical analysis. Unfortunately, the diversity of available samples is limited, and the cost of obtaining or manufacturing others is prohibitive. Moreover, inspection conditions cannot be anticipated by samples.

An alternative approach is mathematical modeling, either analytic or numerical. Physical theories and knowledge of the geometry of manufactured components can be used to simulate the procedures and techniques used in the field, and inspection scenarios can be studied by means of controlled inputs into models. Material characteristics—size, shape, orientation, and surface roughness—can be related to the effects they have on ultrasonic echoes. The leeway that models afford can be used to evaluate existing inspection practices, as a basis for the design of new inspection techniques, and to develop guidelines for

Figure 2 Analytic results from Ames Laboratory, showing reflector surfaces of the simplified intergranular stress corrosion crack model (**a**) and the corresponding ultrasonic echoes from crack branches (**b**). The horizontal baseline in (**a**) represents the inner diameter region of a pipe; the vertical line represents the propagation of the crack (branches 1 and 2) inward toward the outer diameter region.



component designs in which ultrasonic inspectability is a design consideration.

Analytic models are based on the physics of sound scattering and on the geometry of the scatterer. These models consist of mathematical equations that describe echo formation when sound impinges on a specific kind of reflector. Figure 2 illustrates the kind of information that analytic models produce. Relating reflector components with particular echo segments is a major goal of the modeling work. Inspectors can analyze echo patterns in this context to obtain an idea of the topography of the discontinuity being examined.

Numerical models use iteration techniques. A scattering solution at a particular beginning point is estimated by the modeler. The next solution point is then generated by using the initial (estimated) solution in a recursion relation, a relation that allows successive quantities to be computed; that is, how the nth and $n + 1$ results must be related. The process of iteration continues until some predetermined stopping criterion is satisfied. In many instances, experimental ultrasonic signals are used as starting points in numerical models to generate solutions to scattering problems.

In general, numerical methods apply to very complex problems, ones for which analytic solutions are not available. Numerical results are also used, however, to modify analytic models. Likewise, analytic models are used in developing recursion relations for the numerical methods. Although analytic models provide more insight into the physics of scattering ultrasound waves than do numerical models, they are often oversimplified and thus are limited to well-defined inspection problems.

EPRI is supporting several studies of analytic and numerical modeling of intergranular stress corrosion cracking and also has experimental benchmark studies under way. Ames Laboratory (Iowa State University), in conjunction with Northwestern University, is working on analytic models of cracking (RP2687-1). The results shown in Figure 2 are from this project.

Finite-element modeling, a numerical technique, is being studied at Colorado State University (RP2687-2). The objective of an EPRI-sponsored project at Drexel University is to quantify the sound-scattering effects of centrifugally cast stainless steel (RP2405-18). And experimental verification of these efforts is being conducted at Georgetown University (T301-21).

It is hoped that workshops can be conducted to transfer the results of these projects to utilities and inspection vendors by the end of 1986. *Program Manager: Mohamad Behravesh; Project Manager: Michael Avioli, Jr.*

New Contracts

Project	Funding/ Duration	Contractor/EPRI Project Manager
Advanced Power Systems		
Instrumentation and Monitoring Plan for Red Boiling Springs Electric (RP2612-10)	$63,000 11 months	Tennessee Valley Authority/*E. DeMeo*
Life Extension Assessment of Hot-Section Components: Rejuvenation of Gas Turbine Blade Alloy (RP2775-1)	$92,500 20 months	Rockwell International Corp./*R. Viswanathan*
Coal Combustion Systems		
Characterization of Ceramic Filter Materials for Pressurized Fluidized-Bed Combustion Systems (RP1336-12)	$43,000 22 months	Semler Materials Services/*W. Bakker*
Advanced Nondestructive Evaluation for Creep Damage (RP1865-7)	$684,000 32 months	Southwest Research Institute/*J. Scheibel*
Performance Assessment of Mechanical Condenser Cleaning Systems (RP2300-11)	$65,000 7 months	Sargent & Lundy/ *J. Bartz*
Life Assessment Methodology for Turbogenerator Rotors (RP2481-3)	$655,000 15 months	J. A. Jones Applied Research Co./ *R. Viswanathan*
Evaluation of Pressure-Hydrated Calcitic Limes (RP2533-13)	$42,000 6 months	University of North Dakota Energy Research Center/*G. Offen*
Life Extension Strategy for Fossil Fuel Plants (RP2596-6)	$375,000 8 months	Pacific Gas and Electric Co./*D. Broske*
Life Assessment Methodology for Turbogenerator Rotors (RP2785-1)	$398,000 15 months	J. A. Jones Applied Research Co./ *R. Viswanathan*
Electrical Systems		
Advanced HVDC Insulation Development (RP1903-2)	$300,000 45 months	Pacific Gas and Electric Co./*J. Dunlap*
Pyrolysis and Combustion of Utility Materials (RP2028-16)	$208,500 18 months	University of Dayton Research Institute/ *G. Addis*
Thyristor Package Development (RP2443-6)	$373,000 33 months	Powerex, Inc./*H. Mehta*
Electroimpulse Conductor Deicing (RP2845-1)	$85,000 8 months	Wichita State University/ *T. Kendrew*
Energy Management and Utilization		
Solid-Polymer-Electrolyte Hydrogen Generation System: Follow-on Development (RP1086-21)	$253,200 17 months	United Technologies Corp., Hamilton Standard Div./ *B. Mehta*

Project	Funding/ Duration	Contractor/EPRI Project Manager
COMMEND Support (RP1216-11)	$134,000 8 months	Regional Economic Research/*A. Faruqui*
Heat Storage Furnace Commercialization (RP2731-4)	$70,000 4 months	Strategic Decisions Group/*V. Rabl*
Commercial Cool Storage: Field Performance Monitoring (RP2732-5)	$153,000 17 months	Science Applications International Corp./ *R. Wendland*
Low-Cost Concrete Storage Tanks (RP2732-6)	$381,400 12 months	T. Y. Lin International/ *R. Wendland*
Nuclear Power		
Development of Guidelines for Makeup Water Treatment Plant Design and Operations (RPS306-20)	$86,000 11 months	Balazs Analytical Laboratory, Inc./*S. Hobart*
Precipitate Stability in Zircaloy-4 (RP1250-16)	$95,000 20 months	General Electric Co./ *A. Machiels*
Quantitative Aspects of Hydrogen-Assisted Subcritical Crack Growth in Steels in PWR Environments (RP1325-15)	$50,000 16 months	Materials Engineering Associates, Inc./*J. Gilman*
Piping Support Fabrication and Instrumentation for PHDR Seismic Tests (RP1444-10)	$67,500 7 months	EG&G Idaho, Inc./ *A. Singh*
Update on Radwaste Generation Survey (RP1557-26)	$70,000 6 months	Analytical Resources, Inc./*P. Robinson*
X-Ray Residual Stress Study of ¾-Inch Alloy 600 U-Bend Tubes (RP2163-8)	$55,000 25 months	Pennsylvania State University/*A. McIlree*
Emergency Procedures Tracking and Evaluation System (RP2347-17)	$317,000 20 months	Nuclear Software Services/*D. Cain*
Historical Crustal Deformation and Seismic Activity in Eastern Maine (RP2556-23)	$39,400 8 months	Massachusetts Institute of Technology/*C. Stepp*
Advanced Engineering Workstation With Nuclear Fuel Management Applications: Performance Assessment (RP2614-8)	$41,800 13 months	North Carolina State University/*O. Ozer*
Low-Volatility pH Control for PWRs (RP2647-2)	$44,000 10 months	San Diego State University Foundation/*T. Passell*
Automated Ultrasonic Inspection of an Upper Shell-to-Cone Steam Generator Weld (RP2673-6)	$99,800 3 months	Westinghouse Electric Corp./*M. Avioli*
Evaluation of Cross-Section Generator Code Discrepancies (RP2803-1)	$81,200 6 months	Control Data Corp./ *O. Ozer*
Development of Seismic Functionality Requirements for Relays (RP2849-1)	$169,000 13 months	MPR Associates, Inc./ *R. Kassawara*

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

Integrated Two-Stage Coal Liquefaction Batch Catalyst Operations: Advanced Coal Liquefaction R&D Facility, Wilsonville, Alabama
AP-4609 Final Report (RP1234-1, -2); $70
Contractor: Southern Company Services, Inc.
EPRI Project Manager: W. Weber

Heber Binary-Cycle Geothermal Demonstration Power Plant: Summary of Technical Characteristics
AP-4612-SR Special Report (RP1900-1); $25
Contractor: San Diego Gas & Electric Co.
EPRI Project Manager: J. Bigger

Chemistry and Uses of Carbon Dioxide
AP-4631 Final Report (RP2563-5); $32.50
Contractor: University of Pittsburgh
EPRI Project Manager: C. Kulik

Solano MOD-2 Wind Turbine: Operating Experience, September 1984–August 1985
AP-4638 Final Report (RP1590-6); $25
Contractor: Pacific Gas and Electric Co.
EPRI Project Manager: F. Goodman

Wind Power Stations: 1985 Performance and Reliability
AP-4639 Final Report (RP1996-2); $32.50
Contractor: R. Lynette & Associates, Inc.
EPRI Project Manager: F. Goodman

Gasification–Combined-Cycle Plant: Part-Load Performance
AP-4653 Final Report (RP2029-15); $25
Contractor: Fluor Technology, Inc.
EPRI Project Manager: A. Lewis

EPRI Mobile Geothermal Laboratory
AP-4655 Final Report (RP741-1); $32.50
Contractor: Rockwell International Energy Systems Group
EPRI Project Managers: E. Hughes, M. Angwin, J. Jackson, M. McLearn

COAL COMBUSTION SYSTEMS

Coal Cleaning Test Facility Campaign Report No. 4: Kentucky No. 11 Seam Coal
CS-4434 Interim Report (RP1400-6, -11); $32.50
Contractors: Kaiser Engineers, Inc.; Science Applications International Corp.
EPRI Project Managers: J. Hervol, C. Harrison

Proceedings: 1984 Power Plant Performance Monitoring Workshop
CS-4545-SR Proceedings; $70
EPRI Project Manager: F. Wong

Guidelines for Maintaining Steam Turbine Lubrication Systems
CS-4555 Final Report (RP1648-7); $600
Contractor: Southwest Research Institute
EPRI Project Managers: T. McCloskey, S. Pace

ELECTRICAL SYSTEMS

Development of the JetMole Cable-Replacement System: Field Test Program
EL-4467 Interim Report (RP1287-1); Vol. 1, $25
Contractor: Flow Industries, Inc.
EPRI Project Manager: T. Kendrew

HVDC Transmission Line Insulator Performance
EL-4618 Interim Report (RP1282-2); $25
Contractor: General Electric Co.
EPRI Project Manager: J. Dunlap

ENERGY ANALYSIS AND ENVIRONMENT

Geochemical Behavior of Chromium Species
EA-4544 Interim Report (RP2485-3); $40
Contractor: Battelle, Pacific Northwest Laboratories
EPRI Project Manager: I. Murarka

Nitrogen Input/Output Relationships in Tennessee Forests
EA-4577 Final Report (RP1727); $32.50
Contractor: Tennessee Valley Authority
EPRI Project Manager: J. Huckabee

Speciation of Selenium and Arsenic in Natural Waters and Sediments
EA-4641 Final Report (RP2020-1, -2); Vol. 1, $25; Vol. 2, $25
Contractors: Old Dominion University; Battelle, Pacific Northwest Laboratories
EPRI Project Managers: J. Huckabee, D. Porcella

ENERGY MANAGEMENT AND UTILIZATION

Monitoring of Improved Air-Source Heat Pumps
EM-3978 Final Report (RP789-3); $40
Contractor: Carrier Corp.
EPRI Project Managers: J. Calm, C. Hiller

Radiation Curing: State-of-the-Art Assessment
EM-4570 Final Report (RP2613-3); $40
Contractor: Battelle, Columbus Division
EPRI Project Manager: L. Harry

Cogeneration for a Utility–Co-owned Industrial Park
EM-4581 Final Report (RP1276-18); Vols. 1–4, $32.50 each
Contractors: Burns & McDonnell Engineering Co.; United Technologies Research Center
EPRI Project Manager: D. Hu

Underground Cavern Excavation
EM-4587 Final Report (RP1791-12); $32.50
Contractors: Cementation Company of America, Inc.; Acres American, Inc.
EPRI Project Managers: R. Schainker, B. Mehta

Transferability of Results From Direct Load Control (DLC) Experiments
EM-4588 Final Report (RP2047-2); $25
Contractor: Booz-Allen & Hamilton, Inc.
EPRI Project Managers: W. Smith, E. Beardsworth

Impact of Computer-Integrated Manufacturing on Electricity End Use
EM-4616 Final Report (RP2613-7); $32.50
Contractor: Technology Research Corp.
EPRI Project Manager: D. Hu

Design of Load Control Experiments for the Athens Automation and Control Experiment
EM-4628 Interim Report (RP2342-1); $32.50
Contractors: Minimax Research Corp.; ECC, Inc.
EPRI Project Manager: S. Braithwait

NUCLEAR POWER

Fuel Consolidation Demonstration: Program Overview
NP-4327 (Rev. 1) Interim Report (RP2240-2); $25
Contractor: Northeast Utilities Service Co.
EPRI Project Manager: R. Lambert

Coordination of Safety Research for the B&W Integral System Test Program
NP-4353-SR Special Report; $40
EPRI Project Manager: J. Sursock

Performance of Industrial Facilities in the Mexican Earthquake of September 19, 1985
NP-4605 Final Report (RP1707-30); $25
Contractor: EQE Incorporated
EPRI Project Managers: G. Sliter, R. Kassawara

Techniques for Determining the Radiological Impacts of Hydrogen Water Chemistry
NP-4621 Interim Report (RP1930-8); $25
Contractor: Advanced Process Technology
EPRI Project Manager: C. Wood

Stress Corrosion Characterization of Turbine Rotor Materials: Phase 2
NP-4622 Final Report (RP1929-5); $25
Contractor: The Metal Properties Council, Inc.
EPRI Project Manager: R. Jones

CALENDAR

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

SEPTEMBER

17–19
International Utility Symposium: Health Effects of Electric and Magnetic Fields
Toronto, Canada
Contact: Robert Patterson (415) 855-2581

22–25
Seminar: Partial-Discharge Testing and Radio-Frequency Monitoring of Generator Insulation
Toronto, Canada
Contact: James Edmonds (415) 855-2291

23–24
Workshop: CAES Geotechnology (Porous Media)
Traverse City, Michigan
Contact: Ben Mehta (415) 855-2546

23–26
Workshop: Gas Turbine Procurement and Repowering
Pittsburgh, Pennsylvania
Contact: Henry Schreiber (415) 855-2505

24–25
Industrial Applications of Adjustable-Speed Drives
Washington, D.C.
Contact: Marek Samotyj (415) 855-2980

OCTOBER

7–9
1986 Fuel Oil Utilization Workshop
Philadelphia, Pennsylvania
Contact: William Rovesti (415) 855-2519

14–15
Assuring Power Quality
Baltimore, Maryland
Contact: Marek Samotyj (415) 855-2980

14–15
1986 EPRI Cogeneration Symposium
Washington, D.C.
Contact: David Hu (415) 855-2420

14–16
Seminar: Solid-Waste Environmental Studies Technology Transfer
Milwaukee, Wisconsin
Contact: Ishwar Murarka (415) 855-2150

15–16
6th Annual EPRI Contractors' Conference on Coal Gasification
Palo Alto, California
Contact: Neville Holt (415) 855-2503

23–24
4th EPRI Reactor Physics Software Users Group Meeting
Chicago, Illinois
Contact: Walter Eich (415) 855-2090

NOVEMBER

5–6
Industrial Applications of Adjustable-Speed Drives
New Orleans, Louisiana
Contact: Marek Samotyj (415) 855-2980

5–7
Symposium: Market Research
Kansas City, Missouri
Contact: Larry Lewis (415) 855-8902

10–12
1986 Seminar on BWR Corrosion, Chemistry, and Radiation Control
Palo Alto, California
Contact: Daniel Cubicciotti (415) 855-2069

11–13
Workshop: Power Plant Performance Monitoring and System Dispatch Improvement
Alexandria, Virginia
Contact: Robert Leyse (415) 855-2995

17–19
Marketing Electrotechnologies to Industry
Atlanta, Georgia
Contact: I. Leslie Harry (415) 855-2558

DECEMBER

1–2
Seminar: Coal Transportation Costing and Modeling
San Diego, California
Contact: Edward Altouney (415) 855-2626

1–3
Fly Ash and Coal Conversion By-products
Boston, Massachusetts
Contact: Ishwar Murarka (415) 855-2150

2–4
Workshop: Control Systems for Fossil Fuel Power Plants
Atlanta, Georgia
Contact: Robert Leyse (415) 855-2995

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