Designing the Advanced LWR

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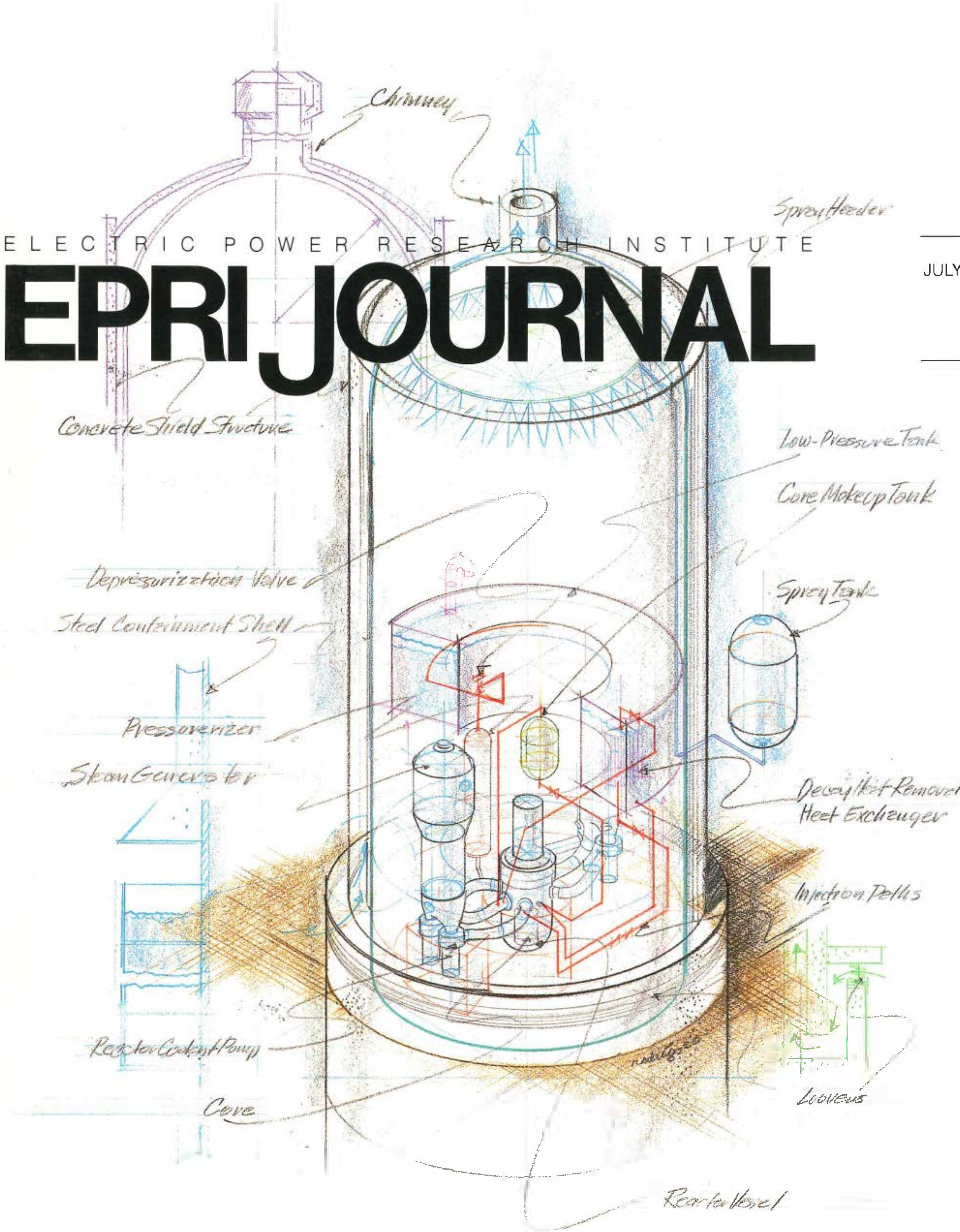

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Cover: Evolutionary in concept, the smaller and far simpler advanced LWR could have a revolutionary impact on the future of nuclear power, especially in the areas of safety and cost.

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The Opportunity for Small Reactors


Taylor

The nuclear power industry is in a period of transition. Although utilities remain convinced that light water reactors (LWRs) represent a sound technology, they will require advances in design based on their two decades of operating experience before making major commitments to new nuclear power capacity. EPRI's Advanced LWR Program is responding to this need by preparing detailed specifications for the next generation of reactors, which are based on lessons learned from operating experience with the current-generation plants. Major objectives of this program are simplifications of operating systems and passive safety features that minimize the need for human intervention or external power to handle emergency conditions, reduced capital cost, and increased plant life.

An important part of the Advanced LWR Program is an evaluation to see whether small reactors, ≤600 MW (e), can also be competitive. This quest challenges long-held beliefs of the importance of economy of scale for nuclear plants. The current transition period offers a unique opportunity to reconsider the potential of small nuclear power plants and to evaluate their true cost under current U.S. conditions.

The small-reactor program is seeking to enhance further the simplification, safety, and cost objectives of the overall program by using design, construction, and operative features unique to small systems. The conceptual design work to date shows promise of meeting such a goal with systems having greater natural circulation, more-passive emergency core cooling systems, lower core power density, and greater modular construction potential. The severe accidents—TMI-2 and Chernobyl—the industry has experienced underline the importance of such enhanced features. TMI-2 showed the need to simplify operator response to abnormal conditions. Chernobyl showed the need for such intrinsic safety characteristics as the negative power coefficient typical of U.S. LWRs instead of the positive power coefficient that tends to make the Soviet Chernobyl design unstable.

In the event of a pipe rupture, our small LWRs can have emergency cooling water flow into the reactor vessel under the force of gravity, rather than having to pump it in, and can then remove decay heat from the containment structure through natural convection currents rather than requiring a forced-air cooling system. Such passive safety systems make these small reactors substantially more forgiving, with less dependence on electrical power and other support systems and more time for operators to react to emergency situations. Also, the potential for individual modularization and factory fabrication will better ensure the high level of quality needed in nuclear plant construction.

The aim, then, of EPRI's small-reactor program is to offer utilities the option of simpler, more-reliable nuclear plants that can compete economically and environmentally with coal plants of the 500–600 MW (e) range in the late 1990s.

J J Taylor

John J. Taylor, Vice President
Nuclear Power Division

Authors and Articles

Sugnet Noble Stahlkopf Balu Douglas O'Connell Esselman

Toward Simplicity in Nuclear Plant Design (page 4) focuses on some evolving features of nuclear reactor design that incorporate passive safety systems into simpler, smaller plants. Written by John Douglas, science writer, with technical inputs from three members of EPRI's Nuclear Power Division staff.

William Sugnet, a subprogram manager in the Advanced LWR Program, joined EPRI in 1982 after three years on loan from Westinghouse Electric Corp. to the Nuclear Safety Analysis Center. Before he went to Westinghouse in 1973, Sugnet was in the U.S. Navy nuclear power program for six years, successively a submarine engineering officer and a nuclear power school instructor. He graduated in mechanical engineering from the University of Notre Dame.

Daniel Noble, senior program manager of the Advanced LWR Program, has been at EPRI since May 1985, on loan from Consumers Power Co., where he was responsible for engineering services to the utility's fossil fuel and nuclear plants. Noble completed his BS and MS in metallurgical engineering at Michigan State University. He also has an MBA from Wayne State University.

Karl Stahlkopf, director of the Systems and Materials Dept., has been with EPRI since 1973. He was formerly in the navy for seven years, specializing in nuclear propulsion. A University of Wisconsin graduate, he also holds MS and PhD degrees in nuclear engineering from the University of California at Berkeley. ■

Planning for HVDC Transmission (page 14) discusses the integration of dc transmission into the nation's ac grids, including the challenges for utility system planners. Written by Michael Shepard, *Journal* feature writer, aided by a staff member of EPRI's Electrical Systems Division.

Neal Balu, manager of the system planning subprogram, has been with EPRI since 1979. Before that he spent seven years as manager of the system dynamics section in the system planning department of Southern Company Services, Inc., and four years on the faculty of the Indian Institute of Technology in Bombay. After coming to North America, he earned three graduate degees in electrical engineering, including a PhD at the University of Alabama, and an MBA at Santa Clara University. ■

Fleet Vans Lead the Way for Electric Vehicles (page 22) reports on a commercial vehicle, a commercial market, and the technology push that is planned to expand them both. Written by Jonathan Cohen, science writer, with guidance by the managers of electric transportation research in EPRI's Energy Management and Utilization Division.

Lawrence O'Connell, project manager for vehicle evaluation and component development, joined EPRI in April 1985 after 30 years with Lawrence Livermore National Laboratory. During 1974, when he worked briefly with the Atomic Energy Commission, and after his return to LLL, O'Connell planned and managed a number of automotive power system and transportation research efforts. He is an engineering graduate of the U.S. Naval Academy.

David Douglas, program manager, has been with EPRI since 1979, mostly involved in the development of batteries for electric vehicle and electric utility uses. He was formerly with Gould, Inc., for 15 years as an R&D director and vice president. Before that he worked for General Electric Co. for 13 years. Douglas holds BS and PhD degrees in physical chemistry from the California Institute of Technology. ■

The Utility Planner's Library: Software for Hard Decisions (page 30) describes more than 40 computer programs for everything from planning a 20-year corporate future down to sizing a distribution substation. The compilation comes from EPRI's director of engineering assessment and analysis.

Walter Esselman has worked in technology assessment and R&D planning since he came to EPRI on loan from Westinghouse Electric Corp. in 1974; he became a staff member in 1975. During 36 years with Westinghouse, he helped organize the company's astronuclear laboratory in 1959, directed the Hanford Engineering Development Laboratory in the early 1970s, and later guided strategic planning for nuclear energy systems. He has a PhD in engineering from the Polytechnic Institute of Brooklyn. ■

TOWARD SIMPLICITY IN NUCLEAR PLANT DESIGN

Simpler, smaller nuclear plants can offer significant advantages in the areas of greatest concern to today's nuclear industry: construction costs and safety. Evolutionary designs that stress standardization, constructibility, and passive safety systems are now on the drawing boards.

When EPRI initiated its Advanced Light Water Reactor (LWR) Program to develop simplified, standardized nuclear power plants for the 1990s, it adopted an evolutionary approach. Specifically, radical departures from current technology were eschewed in favor of changes based on long operating experience with standard LWR reactors and extensive R&D related to these nuclear systems. In this way, a truly advanced design offering substantial improvement over present reactors could be produced without having to build expensive, time-consuming demonstration plants before commercial orders could be accepted.

There is, however, one aspect of the Advanced LWR Program that boldly challenges the conventional wisdom regarding plant size: In addition to optimizing large reactors, those up to 1300 megawatts electric (MW), the program includes an effort to develop conceptual designs for smaller nuclear units (400–600 MW) that could compete with comparably sized coal-fired power plants.

This effort runs counter to a long-held tenet of the nuclear power industry—that economies of scale strongly favor building reactors in the 1000-MW range. The rationale behind this traditional opinion is that a much larger proportion of the capital costs of nuclear plants is size-independent compared with the costs of building coal-fired plants. Regardless of size, for example, each nuclear plant must be subjected to the same stringent process of reactor licensing by the Nuclear Regulatory Commission (NRC). All other considerations being equal, the argument is that a utility could reduce the busbar effect of high overhead capital costs by building larger plants.

In recent years, however, other factors have led some utilities to reconsider the question of economies of scale. Large plants are increasingly hard to finance, entail greater liability, and may not match a utility's load growth. Just scaling down the design of today's reactors, however, almost certainly would not produce a competitive small nuclear plant. Instead, some potential advantages inherent in small reactors must be exploited to scale down costs as well. The small reactors must also be designed to meet the same criteria for standardization and enhanced safety expected of larger reactors in EPRI's Advanced LWR Program.

"The conceptual design effort for small nuclear plants represents one of the most exciting research challenges EPRI has undertaken," says Karl Stahlkopf, director of EPRI's Nuclear Systems and Materials Department. "There is no guarantee we can overcome the supposed economies of scale, but progress so far looks very promising. And if the program is successful, competitive small reactors could have a tremendously positive effect on the future of the nuclear option."

Unfulfilled economies

By today's standards, of course, the reactors built in the early days of nuclear power were small indeed, and scaling up took decades. In 1960 the Dresden 1 unit had a generating capacity of only 207 MW, and by 1970 new plants were generating about 500 MW. The first reactor with more than 1000 MW of capacity did not come on-line until 1973. Researchers have been intrigued to find that some of the early, smaller nuclear facilities achieved performance records superior to those of some larger plants built more recently. Retrospective studies also show that the expected economies of scale—although evident in some particular cases—have not appeared across the board.

Direct comparison of costs for different sizes of U.S. nuclear plants is difficult because many small reactors were built several years earlier than the larger ones. Edison Electric Institute, however, has studied the unit capital costs ($/kW) of plants ranging from 600 to 1200 MW with startup dates from 1973 to 1979. The study reveals that per kilowatt capital costs were generally independent of reactor size, although they did vary considerably from one part of the country to another and decreased significantly when more than one reactor was built at the same site. A similar study of unit capital costs for French 900-MW and 1300-MW reactors also shows no economy of scale and demonstrates even more clearly the value of on-site replication, which is easier to accomplish with smaller plants.

Not only have nuclear plants become larger but their complexity has also increased greatly out of proportion to size. Much of this complexity has resulted from the addition of equipment as retrofits in response to changing regulations, rather than as part of a plant's integrated design. A 1000-MW reactor may, for example, have as many as 40,000 valves—many of which could be eliminated by reoptimizing plant design. Such a fundamental simplification is the primary goal of EPRI's Advanced LWR Program.

Once large reactors are simplified and standardized, however, the question of economies of scale and desirability of small nuclear plants arises all over again. Whether advanced reactors of 600-MW capacity or less become competitive in the 1990s will depend mainly on how well they fulfill utility needs for generation expansion at the time and on whether inherent technical advantages can be identified and sufficiently developed. Both of these factors are being scrutinized in the current EPRI study of small nuclear plants.

Small may be beautiful

The main reason for the present renewed interest in small nuclear plants is that they may be better suited to the uncertain load growth and financial constraints now facing many utilities. Projections of the new generating capacity that will be needed by the turn of the century vary widely. If one as-

ACTIVE VERSUS PASSIVE SAFETY SYSTEMS

By employing gravity feed and natural circulation, passive safety systems can reduce reliance on the complicated electromechanical equipment characteristic of today's active systems. The example below compares the approaches to emergency core cooling after a small LOCA caused by a pipe break in the hot leg between a PWR's reactor vessel and steam generator.

LOCA initiation

ACTIVE With an active system high-pressure pumps are turned on automatically when the LOCA is sensed, and they pump water into the reactor from a large storage tank outside the containment structure. These pumps, in turn, are typically cooled by a service water system or by air conditioning—either of which also requires electric power.

PASSIVE In a small PWR with passive safety systems, water from the high-pressure core makeup tank automatically begins to flow by gravity into the reactor vessel, and heat removal is initiated by a heat exchanger submerged inside a storage tank located within the containment structure.

Reactor depressurization

ACTIVE As steam and liquid are released through the pipe break, pressure in the primary coolant loop eventually decreases, allowing switchover from high-pressure to low-pressure pumps for high-volume reactor cooling. Because the release of steam from the reactor loop increases pressure in the containment building, the steam must be condensed by water pumped through spray units at the top of the containment. At the same time, an electric fan cooler using chilled water from outside is started up to remove heat from the inside of the containment building.

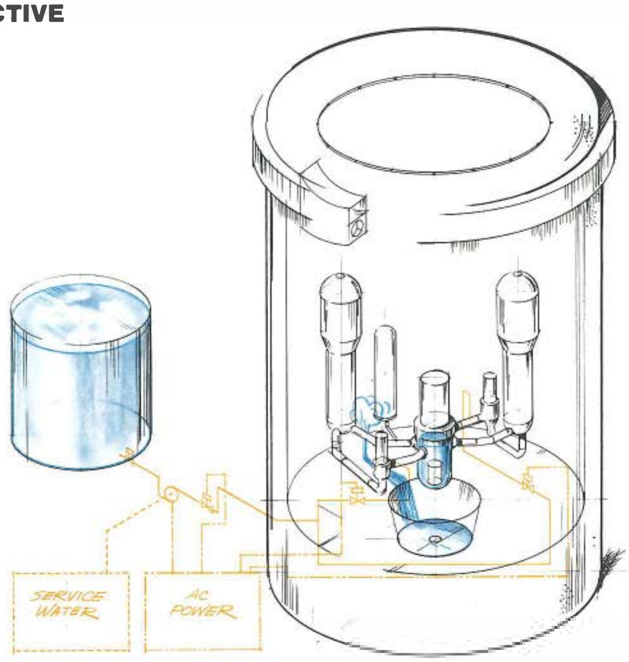
PASSIVE The primary coolant loop is depressurized quickly by a valve that opens to release steam into the large water storage tank, where it is condensed. The water from this tank then flows by gravity into the reactor vessel to flood the core. Water for the containment spray system is propelled by pressurized nitrogen gas rather than by an electric pump.

Long-term cooling

ACTIVE To achieve a long-term stable condition, water from the sump in the bottom of the containment building must be recirculated continuously through the core by several pumps located outside the building.

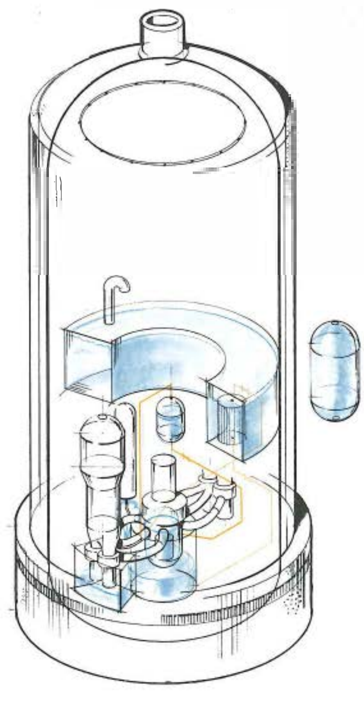
PASSIVE In the passive system the entire lower part of the containment structure can be flooded and the core submerged. Steam rising from this water condenses on the inside of the steel containment shell, while natural circulation outside the shell removes residual heat.

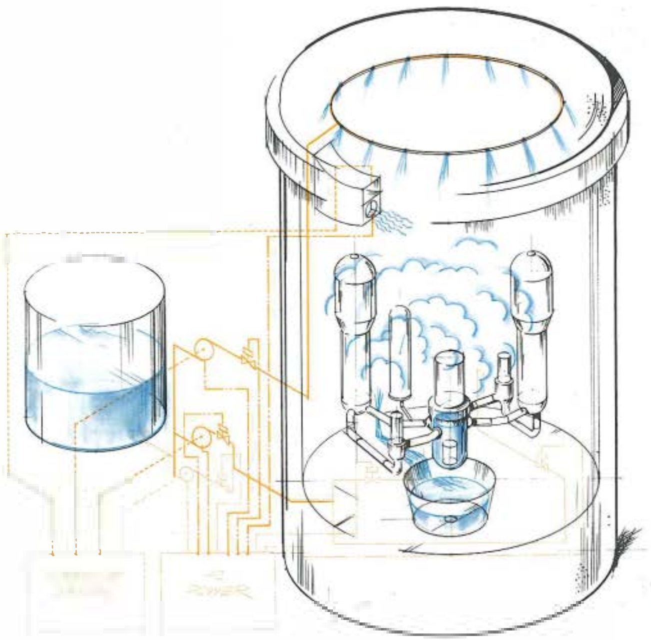
ACTIVE

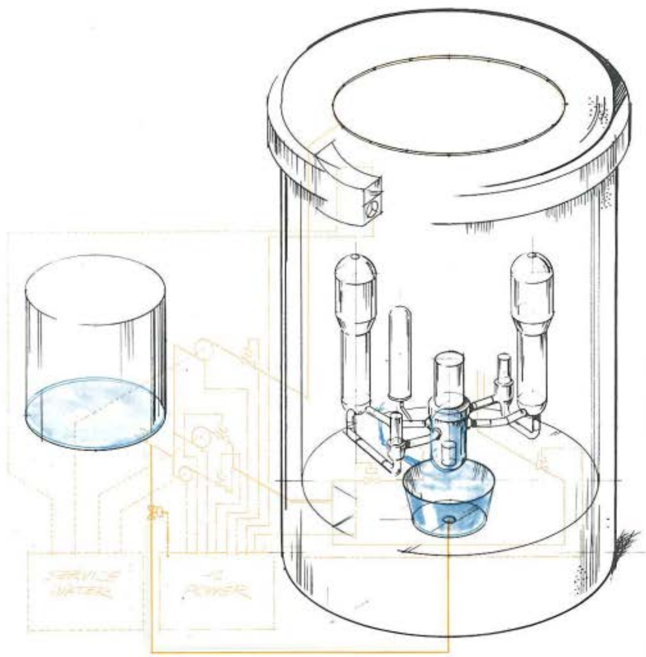


LOCA initiation

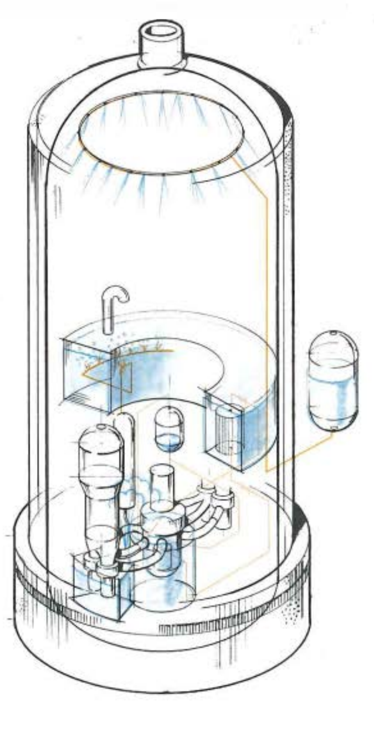
PASSIVE



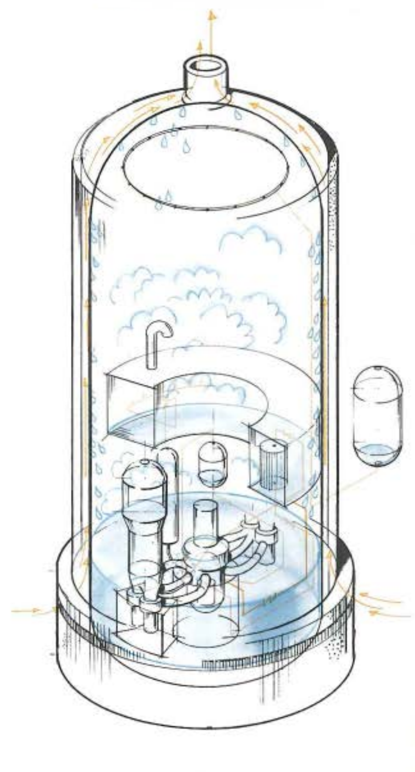




Reactor depressurization



Long-term cooling



sumes the demand for electricity will increase 2% per year, only 42 GW of capacity would have to be added in the United States during the 1990s. If the increase is 4% per year, however, roughly 500 GW of new capacity would be needed.

Faced with such uncertainties, an increasing number of utilities are considering the advantages offered by small power stations, both coal and nuclear. Such plants can provide a closer match between load growth and generating capacity and also offer greater flexibility in responding to changing conditions. If a utility needs capacity growth of about 300 MW per year, for example, then bringing a 1200-MW plant on-line would create overcapacity for four years, while a 600-MW plant would match growth needs after only two years. In addition, should demand change, smaller plants with shorter lead times would allow a utility to respond more rapidly. Already the majority of coal-fired units planned for addition before 1992 are in the 300–700-MW range. Such plants represent the first line of competition that must be met if small nuclear plants are to succeed in the 1990s.

The other major kind of competition comes from large nuclear plants. Although some utilities may judge this contest on the basis of economies of scale alone, many may choose smaller nuclear plants in order to reduce their financial exposure. Because of the enormous expense entailed in building major nuclear facilities, several small-to-medium-size utilities have often had to form joint ventures in order to afford the investment. Recently, however, such partnerships have encountered increasing problems. Public utility commissions from different jurisdictions have sometimes disagreed over how the various partners are to share the income from such projects and have thus hampered investment recovery. In other cases, failure of large nuclear projects has created unprecedented financial losses and disagreements over the liability for those losses among the utilities and regulatory bodies involved.

If shared ownership of large nuclear plants continues to lose favor, more individual utilities are likely to choose small plants, provided they can be built competitively. A widely accepted rule of thumb states that a utility should not have more than 10% of its capacity in one plant in order to limit the effect an outage at that plant would have on the rest of the system. According to this rule, only a few U.S. utilities have systems large enough to absorb a 1000-MW nuclear plant by themselves. A significant number, however, have systems with capacities in the range of 6000 MW, for which the optimal unit size for construction around the end of this century would be about 600 MW, assuming 2% load growth and plant lead time of five years.

Given this apparent need for small nuclear plants, what specific criteria will they have to meet to compete with coal plants of the same size and with larger nuclear plants? "We would like to see busbar costs 10–20% less than those for today's coal," says William R. Sugnet, program manager. "That translates into a program objective of about 6.5¢/kWh in terms of 1985 dollars levelized over 30 years of plant operation. Even if the cost of hardware per kilowatt of capacity turns out to be greater for small plants, we believe a utility could make up the difference in shorter lead time and lower finance charges to arrive at a comparable busbar cost."

The technical challenge

Design simplification can improve safety and reliability, as well as reduce the number of expensive systems and components included in a reactor. Small plants particularly lend themselves to such simplification because of their ability to use passive safety systems—that is, emergency equipment having reduced dependence on power-driven components and operator action. In smaller reactors, the use of a full-pressure, natural convection circulation system for removing decay heat also appears to be practical. In this way, no reliance need be placed on electric pumps under emergency conditions. In addition, large supplementary tanks of water can be placed above the core to flood it passively (using only the force of gravity) during a loss-of-coolant accident (LOCA). Use of such tanks in a large reactor would be much more expensive and complicated.

Among the safety systems in current reactors, emergency diesel generators are provided that can be started quickly to provide power to safety system pumps in case of power failure. These generators have to be able to begin generating electric power very rapidly to meet current NRC requirements and must be tested periodically under simulated emergency conditions. An important benefit of having larger water volumes, enhanced natural circulation, and passive safety systems in small reactors is that the emergency diesel generators can either be used in a less demanding mode of operation and testing or, perhaps, eliminated entirely.

Some of the current design changes reflect a renewed emphasis on preventing the onset of a serious accident, as well as continuing to focus on mitigating the effects of an accident once it occurs. EPRI has adopted a goal of limiting the likelihood of severe core damage in advanced LWRs to one chance in a hundred thousand per year. Such design improvements are possible, in part, because of favorable results from research jointly sponsored over the last decade by EPRI, NRC, and reactor vendors (*EPRI Journal*, March 1986). Extensive experiments conducted on the emergency core-cooling system of reactors under LOCA conditions, for example, have shown that considerable margin exists for simplifying these systems without affecting plant safety. Other research indicates that release of radioactivity outside a containment building during postulated severe accidents is likely to be much lower than that assumed in past regulatory practice.

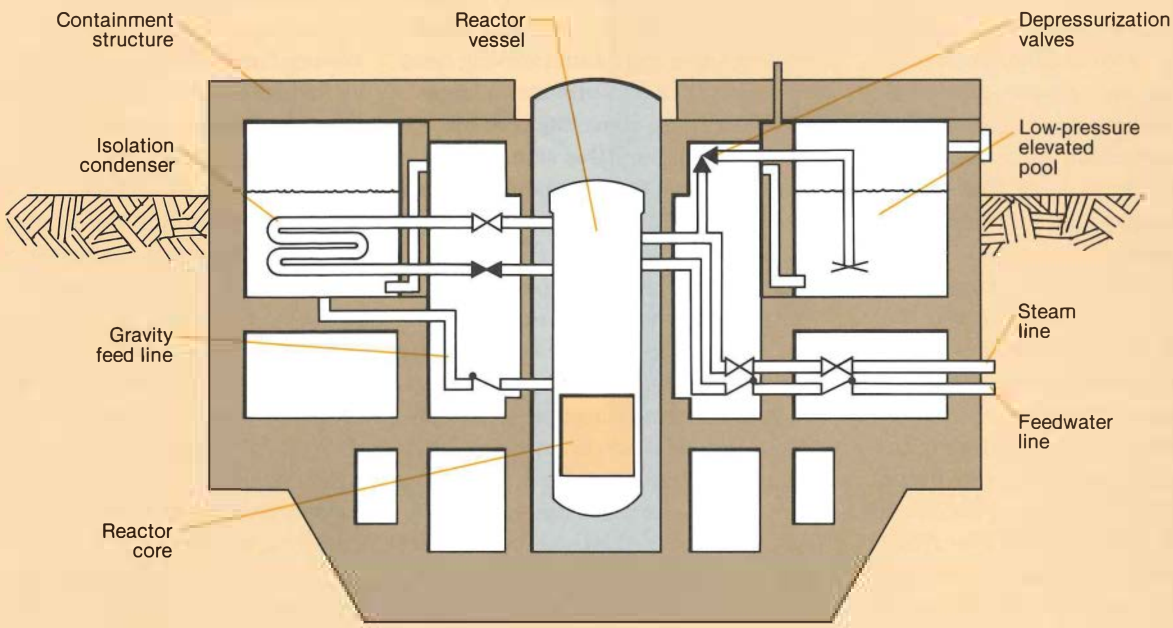
Considerable research has also been conducted on how to improve reactor control rooms. Most of these improvements apply equally to both large and small reactors, except that smaller plants should be inherently easier to control because of their simplicity and greater reliance on passive safety systems. An advanced control room could use modern electronic graphics and a computerized data base to give operators a better overview of plant status. In the event of abnormal conditions, diagnostic aids that use artificial intelligence techniques could provide quick guidance to operators. The key to improvement will be the prudent use of advanced technologies to simplify operations without adding complications to plant systems and equipment.

Each of the conceptual small-plant designs that EPRI is pursuing will feature a core and a reactor vessel that are proportionately larger than those used in today's conventional nuclear plants. This increased volume means that the power density in the uranium fuel rods will be reduced by as much as 30%. Lower power densities and relatively larger volumes of water in the core mean that a reactor would heat up more slowly if problems develop in the external cooling system. This longer response time makes the plant more forgiving—easier to operate under normal conditions and more controllable during an accident. Lower power densities can also enable a utility to adopt a 24-month refueling schedule, rather than following the conventional practice of shutting down a plant each 12–18 months for refueling.

To meet the cost targets for small reactors, innovative approaches to design and construction must be followed. In particular, the current program is emphasizing modularization and factory fabrication of simplified reactor systems, which can lead to shorter construction schedules. Smaller plants lend themselves to such techniques, which generally increase productivity and offer better opportunities for quality assurance. Standardization of components can significantly reduce the time required to make each piece, while experienced shopcraft labor reduces the need to train and supervise new workers in the field. Reuse of tooling and fabrication facilities for a series of plants

Passive Safety for BWRs

The passive safety systems for a small BWR center on an elevated pool of water that encircles the reactor. In the event that the normal reactor heat removal systems become unavailable, decay heat is removed by circulation of coolant from the reactor vessel through an isolation condenser submerged in the pool. If a LOCA were to occur, steam from the reactor would be vented into the pool to depressurize the reactor coolant system. Once depressurization is accomplished, water from the elevated pool can flow into the reactor vessel by gravity for long-term cooling.



could provide a major cost saving. Shipment of completed modules can make on-site assembly easier and more precise. For some sites, a whole reactor might be constructed on a barge and carried as a unit to the plant site.

Design opportunities

EPRI's program to develop conceptual designs for small nuclear plants is now nearing completion of Phase 1, in which various design options are being screened. Three research teams are participating in this initial phase of the program. Westinghouse Electric Corp. and Burns and Roe, Inc., are designing a small pressurized water reactor (PWR) with a recirculating steam generator, while Babcock & Wilcox Co. and United Engineers & Constructors, Inc., are focusing on a small PWR with a once-through steam generator. General Electric Co., Bechtel National, Inc., and the Massachusetts Institute of Technology are designing a small boiling water reactor (BWR). Phase 2, which involves further development of the most promising designs and cooperative supporting research with the U.S. Department of Energy (DOE), began in June and will continue through 1989.

An important feature in the design of small PWRs is the configuration of primary coolant piping between the reactor vessel and the steam generators. The steam generator separates the primary coolant from the boiling coolant in the secondary loop that drives the turbine generator. Current PWRs have a crossover pipe in each primary coolant loop, which connects the outlet of the steam generator to the inlet of large shaft-sealed coolant pumps. This crossover pipe forms a low point in the loop, which could act as a water trap to cause uncovering of the reactor core during a small LOCA. The reactor coolant pumps have caused plant unavailability due to failures in the seal on the rotating shaft that prevents loss of coolant from the pump.

Westinghouse proposes to replace each large, shaft-sealed coolant pump with two smaller pumps that are hermetically sealed by a metallic can between the motor windings and the coolant and are mounted directly in the bottom of the steam generators. Babcock & Wilcox proposes a similar approach, using a hermetically sealed, wet-winding pump and a crossover pipe that does not form a low point in the primary coolant loop. These configurations would eliminate both the troublesome seal and the low point in the crossover pipe. The newly designed loops would also offer less resistance to coolant flow. The feasibility of these improved configurations depends on successful adaptation of hermetically sealed pump motors that have already been used commercially in early PWRs and more-recent BWRs.

An exciting possibility now being explored by the engineers designing the advanced small BWR is that pumps for recirculating reactor coolant might be eliminated entirely. Instead, circulation of coolant within the reactor vessel would be driven naturally by thermal gradients created around the core. A key requirement for obtaining natural circulation in the small BWR is to have a taller reactor vessel. This extra height both enhances the natural driving head for recirculation and provides a larger volume of water above the core for emergency cooling. This side benefit lessens the cost of a plant that features a passive, gravity-driven emergency core-cooling system.

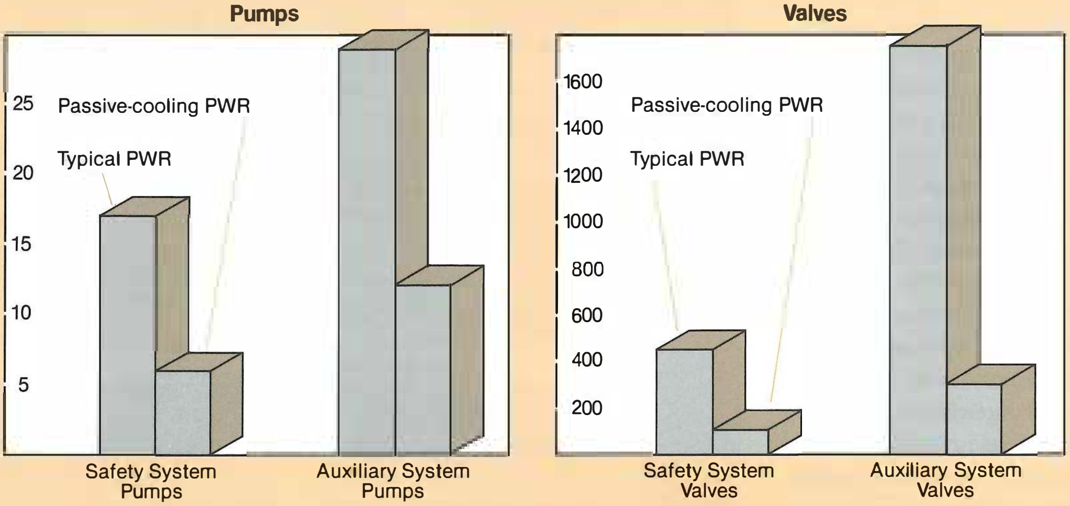
Another promising design opportunity research teams are exploring in small PWRs is that it may be possible to reduce or eliminate boron systems that are used for controlling the nuclear reaction. Soluble boron is now circulated through the core of PWRs in the cooling water, where it absorbs neutrons and promotes even burning of the uranium fuel rods. As an alternative, so-called gray rods, which absorb limited numbers of neutrons, can be used to slow the nuclear reaction and keep the fuel rods from burning unevenly. The use of gray rods reduces the amount of coolant that must be processed to change boron concentration and therefore reduces the auxiliary equipment needed to control boron in a reactor.

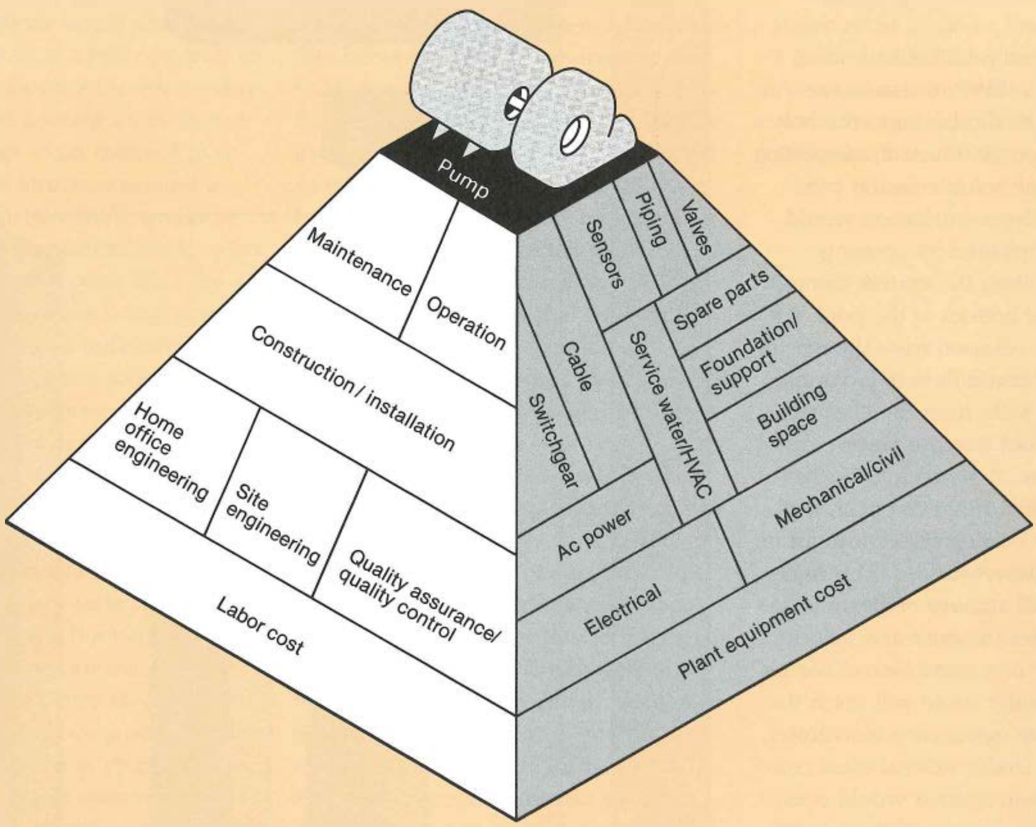
Passive safety systems

After an emergency shutdown, reactor safety systems must perform two separate functions: removal of decay heat from the core and, in the event of a LOCA, replacement of coolant lost from the reactor vessel. In today's reactors, both functions require pumps, which usually rely on a steady supply of electric power from an external line or from an emergency generator. (Steam-driven pumps are used for diversity and protection against station blackout in some plants.) Each of these safety system pumps is also usually cooled by water supplied by auxiliary pumps. Designs for advanced small LWRs offer increased reliance on safety systems that require little human intervention and have no need for power to keep pumps running. This emphasis on passive safety is consistent with the overall goal of simplification in EPRI's Advanced LWR Program.

Removal of decay heat from a small Westinghouse PWR would be provided by natural circulation of coolant through a heat exchanger submerged in a large water storage tank within the containment vessel. In a small Babcock & Wilcox PWR, steam from the steam generator would flow to a condenser outside the containment vessel, where it would be cooled by natural circulation of air. The decay heat removal in a General Electric small BWR would be provided by condensation of steam in a heat exchanger submerged in a large annular suppression pool that forms part of the containment structure and is elevated above the reactor.

Water from the emergency core-cooling system is used to replace coolant in the reactor vessel after a LOCA. In the Westinghouse small PWR, a core





Simplicity Pays Off

The impact of simplification and passive safety systems can be seen clearly in the possibility for reduction of components. Over 60% of the pumps and 80% of the valves required for moving fluids in a conventional LWR can be eliminated in advanced designs that employ gravity feed and other passive concepts. This reduction is expected to simplify operation, increase system reliability, and enhance safety beyond that of conventional designs. In addition, for each valve and pump removed, a mountain of support equipment and operation and maintenance services are also eliminated, significantly reducing cost.

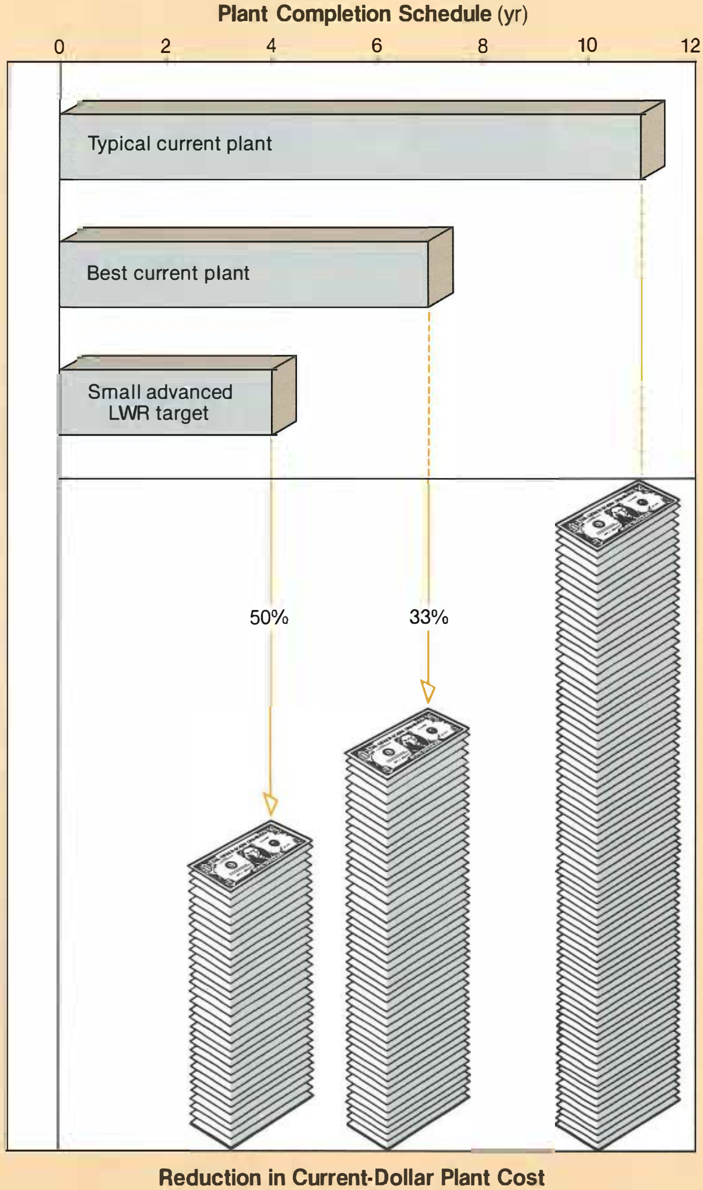
makeup tank designed to operate at full system pressure would supply water by gravity-draining to the reactor vessel while it is being depressurized during a LOCA. Depressurization would be completed by venting the system into the water in the larger, low-pressure storage tank inside the containment structure, which would then drain by gravity to flood the core. In the long term, the entire lower portion of the containment structure would be flooded and coolant would circulate freely to remove decay heat. The Babcock & Wilcox emergency core-cooling system would also use a combination of high-pressure and low-pressure tanks to supply water to the core but would still require some flow from diesel-driven pumps.

In the event of a LOCA in a small General Electric BWR, the steam released would be directed into the bottom of the suppression pool, quenching it and removing soluble fission products. Further depressurization would then be accomplished by opening valves and venting the system through spargers at the bottom of the pool. After pressure is released from the reactor system, water could flow freely under the force of gravity from the elevated suppression pool into the reactor vessel to cool the core. A steam injector has also been included that can push feedwater into the reactor vessel without its having to be depressurized. This injector uses a small amount of steam to increase the water pressure and velocity so that in case of a small leak of reactor coolant, feedwater could still reach the core without an emergency blowdown and flooding. Under normal plant conditions the steam injector would operate continuously as part of the regular feedwater system and would thus be ready to maintain a minimum level of flow automatically if the electrically powered portion of the feedwater system should fail.

One of the most important safety features in a reactor is the containment

Time Is Money

Critics of smaller plants point out that economies of scale work against such downsizing. One way designers plan to keep the overall costs for small plants competitive is by shortening schedules from those of recent larger U.S. plants. Cutting the time for plant completion from the 11 years typical of current plants down to the advanced plant target of 4 years could reduce the interest and inflation component to the point of halving the total plant cost. Further reductions in this total will likely be achieved as ways are found to reduce the costs of materials, labor, and engineering.



Note: Estimates assume the same direct and indirect plant costs, 6% inflation, 2% escalation above inflation, and an interest rate of 12.5%.

structure, which prevents escape of radioactivity to the environment after an accident involving damage to the reactor fuel has occurred. Means must be provided to remove heat from the containment so that it does not become overpressurized and leak. In the small Westinghouse PWR design, the containment structure consists of a steel shell surrounded by an exterior building of reinforced concrete. During a LOCA, steam inside the steel shell would be condensed by water from a passive spray system, driven by pressurized nitrogen. After flooding of the reactor vessel, heat would be removed from the containment structure by natural circulation of air between the steel shell and the outer concrete building.

Babcock & Wilcox would also have a steel shell, as well as a bed of gravel to absorb energy from the blowdown during a LOCA and prevent an excessive pressure buildup. Heat removal from the containment structure around a small General Electric BWR would be provided by a waterwall adjacent to the elevated suppression pool, allowing any radioactivity released during an accident to be contained indefinitely without having to vent gases to the atmosphere to avoid overpressurization.

The overall effect of these passive systems would be to extend the time available for major corrective action to several days following an accident. Water from the large tanks and pools would passively keep temperatures and pressures within safe limits for days without further intervention. Passive heating, ventilation, and air-conditioning systems are also being designed to keep plant conditions in electronics and control areas tolerable even in the unlikely event of a power failure following an accident. Another major improvement in each of the designs being developed is the elimination of the need for large diesel generators. Instead, the new plants would have the water tanks and gravity-driven cooling systems described earlier, as well as a larger capacity to supply power from batteries.

"Small reactors—both PWRs and BWRs—are very attractive," says Daniel M. Noble, senior program manager. "They would be simpler to operate and can include passive safety systems without the need for a radical new design. What the current research effort must demonstrate is that we can lower costs sufficiently through design improvements, shorter lead times, and modular fabrication to make them competitive."

The road ahead

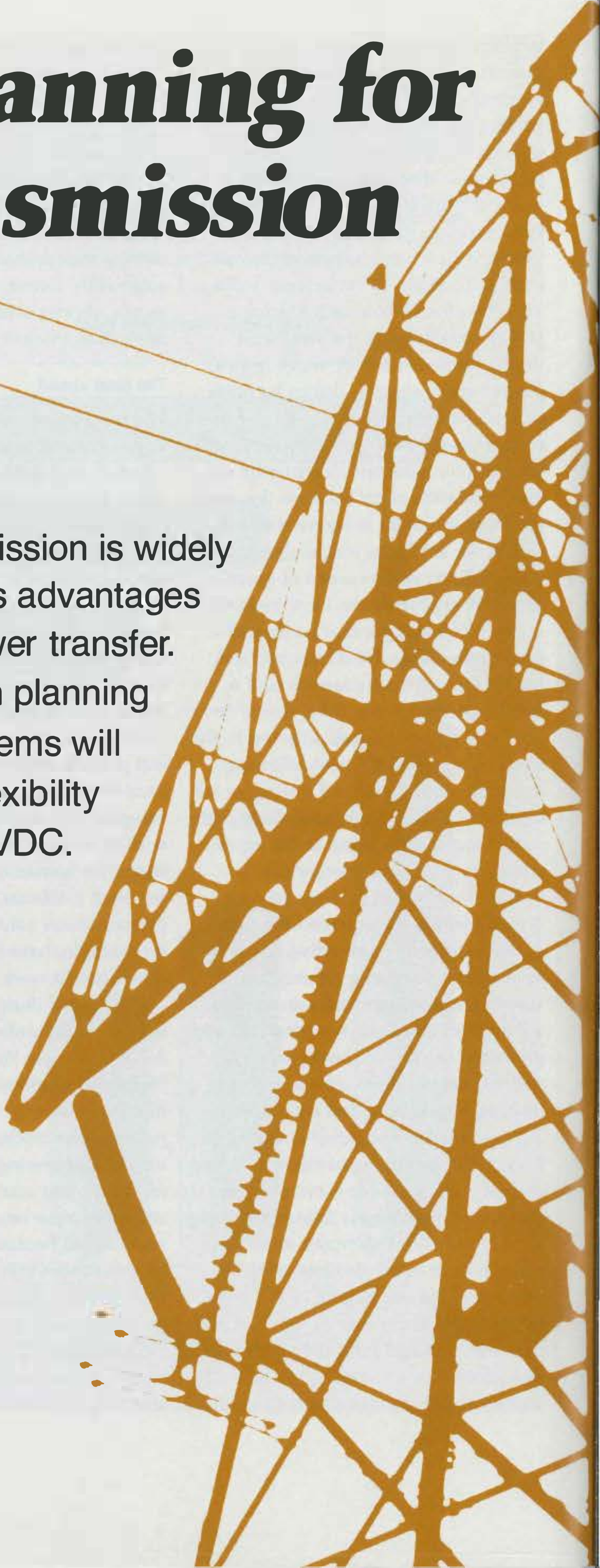
The most promising conceptual designs for small reactors are now being selected, and further development in Phase 2 of the program is scheduled to begin soon. This concentrated development effort will involve close cooperation between EPRI, its contractors, and DOE. For the 1986 fiscal year, Congress has authorized $4.75 million for DOE to use specifically in support of EPRI's Advanced LWR Program, provided the funds are matched evenly by industry cost-sharing. It is expected that DOE will provide about $20 million through fiscal 1989 for projects that support development of specific technologies needed to make the small plants feasible. The hermetically sealed pumps for small PWRs and a new type of depressurization valve for small BWRs, for example, have been selected for this development work.

Conceptual design of small reactors is proceeding under guidance of the Advanced Light Water Reactor Utility Steering Committee. The chairman of that committee, C. Frederick Sears, vice president for nuclear and environmental engineering at Northeast Utilities, says that small nuclear plants should become more attractive in the years ahead because of the limited capital investment that must be committed to each one. "Also, they should be more amenable to shop fabrication, prefabrication, and duplication. Once one has designed the plant, one ought to be able to greatly reduce construction costs and times through the learning process of standardization."

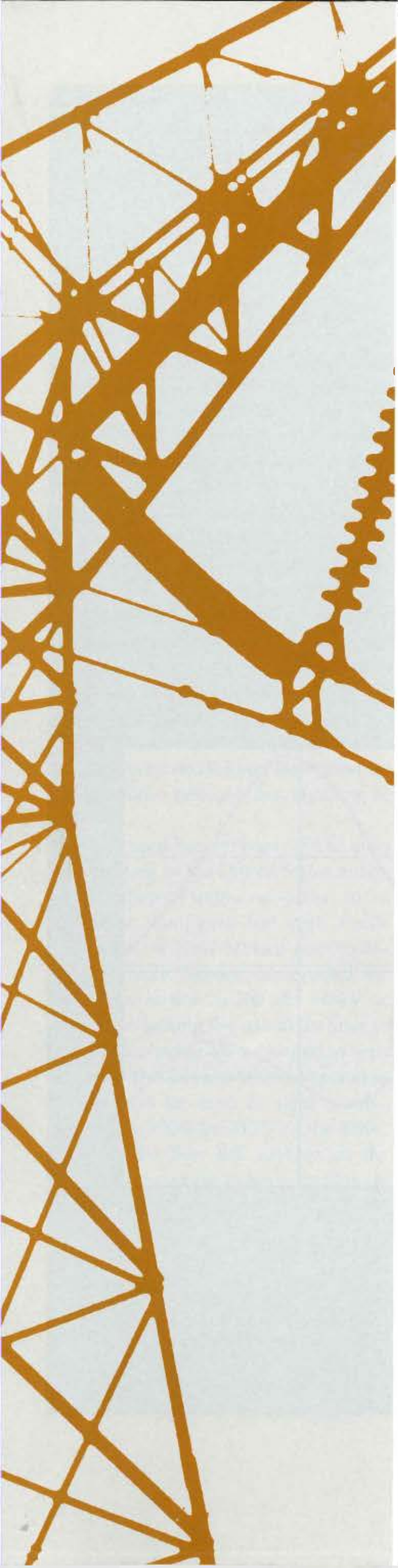
Before small reactors are ready for the assembly line, however, critical questions must be answered about their overall economic viability and the technical feasibility of specific new components and passive safety systems. One important indication that these questions will be answered satisfactorily is that some utilities and research agencies abroad have expressed an interest in becoming partners in EPRI's small reactor design effort. When the Phase 2 effort is completed at the end of 1989 the completed conceptual designs will be evaluated by industry and government. Then, if market conditions and the merits of the basic designs warrant, a larger effort could be launched to create more-detailed designs that would serve as a basis for reactor suppliers to make a commercial offering and obtain certification from NRC. ■

This article was written by John Douglas, science writer. Background information was provided by Karl Stahlkopf, William Sugnet, and Daniel Noble, Nuclear Power Division.

Planning for HVDC Transmission



Dc transmission is widely recognized for its advantages in point-to-point bulk power transfer. Recent advances in planning multiterminal systems will add valuable flexibility to the promise of HVDC.



In 1893, to Thomas Edison's chagrin, the builders of the first major hydroelectric facility at Niagara Falls selected a design supported by George Westinghouse to transmit electric power from the falls as alternating current (ac). Their decision was based primarily on the fact that ac transformers enabled ac power to be transmitted more readily than direct current (dc) the then-considerable distance of 22 mi (35 km) to Buffalo, New York. This project signaled the end of Edison's dream of a power network based on dc and set the stage for a century of global electrification dominated by ac power.

With improvements in dc converters and other components by the middle of this century, however, system planners began to recognize that dc transmission has advantages over ac in a few special situations. Since 1954, when the first commercial high-voltage dc (HVDC) cable was laid from the Swedish mainland to the island of Gotland, about 30 HVDC systems have been installed around the world, converting ac power to dc for transmission and then converting it back to ac for consumer use.

HVDC facilities do not stand alone, however. They must be woven into the existing tapestry of the ac transmission network in a manner that complements the ac system. This poses a challenge to system planners, who must anticipate how various potential configurations of new lines and controls will affect the bulk power system in regular operation, as well as during such disruptions as plant outages or line faults.

The industry has had 90 years of experience in conducting studies on the effect that new ac lines will have on existing grids. But dc technology is still unfamiliar to most system planners, and until recently they have not had adequate modeling tools to help them develop and evaluate their dc system expansion options. New software developed with EPRI support will make it easier for them to consider a broad range of HVDC alternatives. With proper design, dc lines can enhance the stability and performance of an ac system.

The advantages of dc

There are several reasons for the ground swell of interest in HVDC transmission. The first stems from the growing desire within the industry to transfer large blocks of power long distances. Utilities with excess capacity want a transmission system that enables them to sell that capacity and keep consumer rates low. Conversely, many utilities that have insufficient capacity or that must burn expensive fuels want to buy power either to avoid the cost and risk of building new power plants or to reduce fuel costs. Utilities in southern California, for instance, purchase large amounts of low-cost hydroelectricity from the Pacific Northwest and sell power back to northwestern utilities during dry seasons. In such a situation, HVDC can enhance the diversity of exchange between areas with different seasonal sources and seasonal peaks.

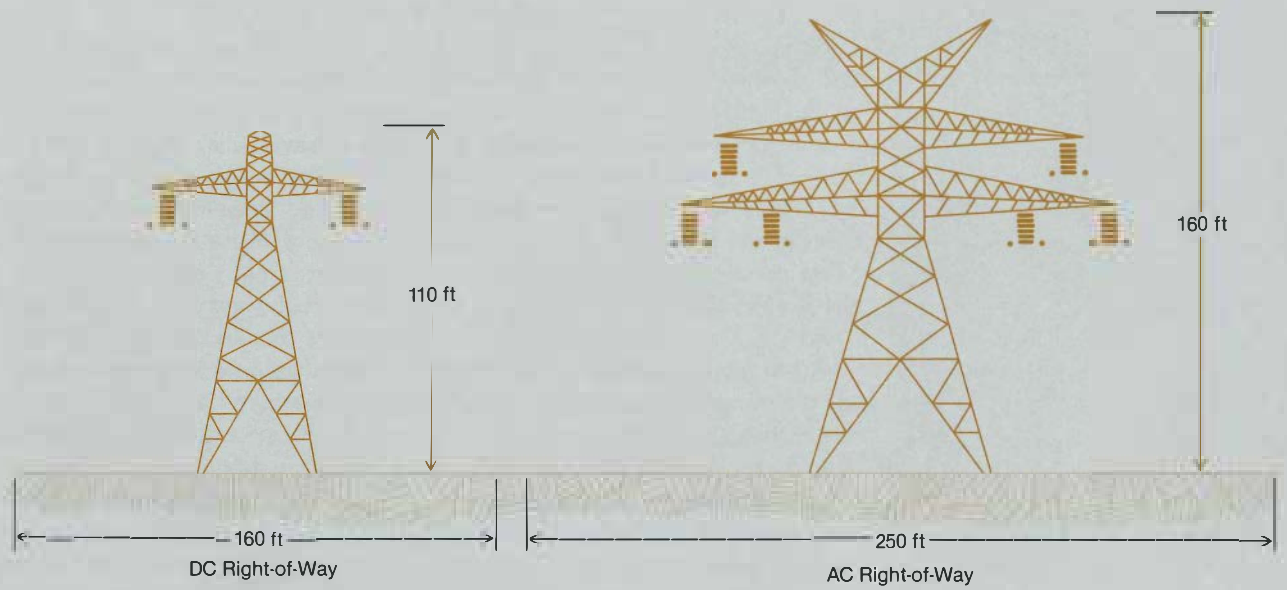
For this kind of application—long-distance bulk power transfer between two points—HVDC transmission is less expensive than ac transmission. The savings arise from several sources. Dc transmission requires fewer conductors than does ac transmission. With fewer conductors, the transmission towers can be smaller. Not only does this reduce the cost for lines and towers, but it means that the right-of-way corridors can be narrower, adding to the cost savings and making it easier to site new lines.

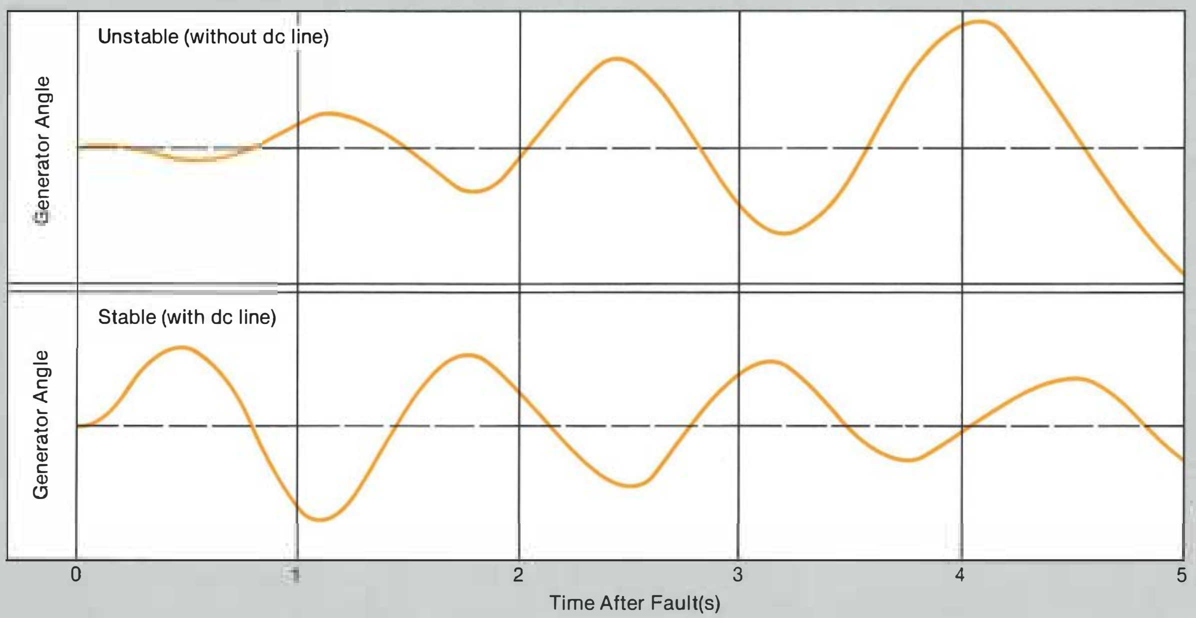
Although the lines and towers cost less for dc transmission, converter stations must be built at each end of an HVDC line to change ac power to dc and vice versa. At some distance, the lower cost of the dc lines and towers overrides the cost of the converters to make the dc alternative cheaper than ac. The crossover point at today's costs is around 310 mi (500 km) for above-ground lines and near 31 mi (50 km) for underground or submarine cable.

HVDC is not only cheaper over long distances but also more efficient. When

Narrowing the Transmission Corridor

Because dc transmission requires only two conductors (rather than the three needed for ac), towers can be more compact—which reduces their cost and allows rights-of-way to be narrower for the same level of reliability.





DC Damping for System Stability

When lightning strikes ac lines, the resultant short circuit causes dynamic imbalances between generators. Within a few cycles of the fault, the generator closest to the fault may have to be momentarily tripped off the circuit, or the instability could grow to such a degree that the entire system is in danger of outage. A dc line tied into the system, however, tends to damp out such instabilities, allowing the system to return to normal operation without the need to isolate a generator unit.

they are not properly compensated, ac lines have to carry a significant charging current, which partially loads the lines and causes line losses. Dc lines, once charged up with dc voltage, do not have a charging current and can therefore carry higher load current with lower losses.

Long-distance bulk power transfer is not the only reason for the new wave of interest in HVDC transmission. Today there are four independent grids in the United States and Canada. A growing number of utilities and utility pools in these grids are interested in forming intergrid links to provide backup system capacity and to increase the opportunities for power exchanges and wheeling. Because these grids are not synchronized, ac links between them are not feasible; instabilities can develop, leading to voltage and power fluctuations and possibly to equipment failures. However, dc facilities offer a safe and effective way of linking ac grids that are not closely synchronized because the dc power flow is more easily controlled and thus provides a stable buffer between the adjoining ac networks.

Six so-called back-to-back HVDC links are operating in the United States today, joining adjacent utility networks. In an installation completed last year, Public Service Co. of New Mexico and Southwestern Public Service Co. opened the Blackwater station, a 200-MW 60-kV dc connection linking the 345-kV ac lines in New Mexico to the 230-kV ac grid in west Texas. For the first few years of operation the line will be used to send surplus power from PNM to SWPS. In the 1990s, however, the flow will reverse, as the Texas utility expects to have surplus capacity, and PNM expects to need imported power.

Another advantage of HVDC lines within ac systems is that they can damp fluctuations that occur in the wake of sudden system disruptions. HVDC links damp out these fluctuations in a manner analogous to the way an adult slows a child on a swing. Rather than using brute force to stop the swing at its maximum speed, the adult waits for the the swing to reach the peak of its arc. At that point a small amount of energy is all that is needed to slow the swing. HVDC lines can be programmed with similar intelligence to stabilize much larger ac networks by grabbing the ac system at critical points in its fluctuation. And because the dc controls use solid-state technology, they respond very quickly.

The planner's task

Although these advantages sound good, they can only be realized if utility system planners understand how such HVDC additions will affect their systems and recommend the integration of dc links into their grids. To acquire this understanding, planners use models to study the effects of HVDC links on ac networks. The planning for multiterminal HVDC systems is an important part of such modeling. Although two-terminal systems are adequate for bulk power transfer between two points, multiterminal HVDC links are expected to have a significant role to play as an integral part of the ac grid system in the future. Only one multiterminal system is operating in the world today (the Sardinia project), although several are now in the planning stages. Models for multiterminal simulation in planning programs will allow an objective evaluation of the role of dc in ac systems and will help indicate where dc will be most effective.

In modeling HVDC systems, simulators with miniature lines, capacitors, resistors, and other devices are used as actual physical models of the ac and dc transmission system. These simulators can be adjusted to mimic the system and are used to study system responses for a period of a few tenths of a second. Digital computer programs employing mathematical models are then used to model the large power system into which the dc links are integrated. The operating parameters determined from the dc simulator are fed into the digital computer models.

Numerous utilities and manufacturers have developed simple digital models to study the effect of HVDC links on ac networks, but these models have not been able to represent large networks, they have not been flexible enough to adapt easily to different expansion scenarios, and most of them are limited to two-terminal HVDC systems.

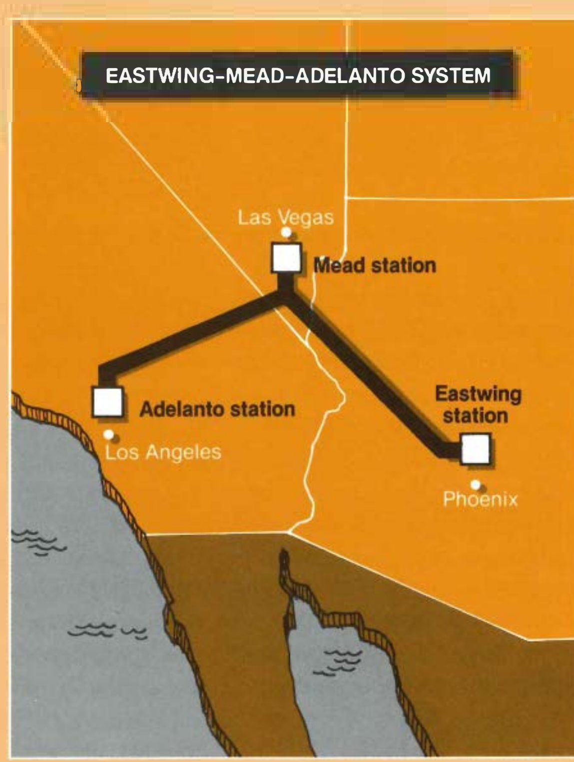
Recognizing the limitations caused by the lack of effective modeling tools, a group of utility system planners serving on EPRI's Power System Planning and Operations task force in the late 1970s recommended that the Institute fund the development of a powerful and flexible computer program for analyzing HVDC links in large ac systems. "We're supposed to plan systems in the most economical and reliable fashion," says Edward Gulachenski, manager of relay and control engineering for New England Electric System, "but we didn't have the tools needed to realistically study HVDC options. What we needed was to be able to do 15–20-year step-by-step system expansion studies, first considering only ac and then considering ac with strategic dc links. We were never able to do that before."

The project was funded, and in May 1983 EPRI published a reference manual explaining techniques for system planners to use in evaluating alternative HVDC reinforcements in ac systems. This manual provides HVDC component costs, explains the basic calculations necessary in evaluating dc system operations, and discusses the differences in dc and ac responses to system disruptions. It specifies the important issues planners should consider, like reactive power, ac system strength, voltage regulation, and harmonic resonance, and shows how different dc converter station configurations and control modes will influence the grid's stability. According to Project Manager Neal Balu, demand for the reference manual has been strong, with more than 800 copies having been distributed throughout the industry.

After publishing this manual, EPRI

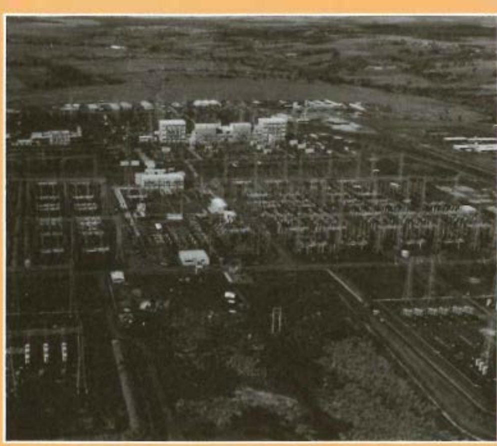
The Future for DC Systems

Multiterminal systems are expected to complete the promise of dc for flexible, long-distance bulk transmission. Such a five-terminal connection in the Northeast is scheduled by 1992 to bring 1.9 GW of hydropower from the primary terminal in northern Quebec to four terminals in Canada and New England. In another project, planned for completion in 1991, a three-terminal ±500-kV dc system will connect key points in California, Nevada, and Arizona. This system will be fully embedded into the region's ac grid.

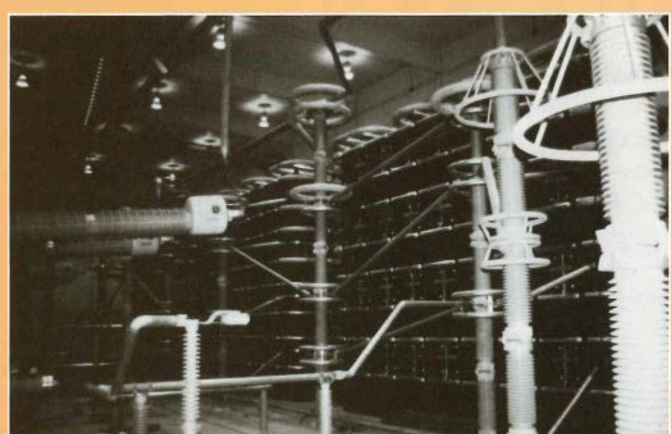


HVDC Conversion Facilities

The converter stations at each end of an HVDC line typically cover a ground area of over a hundred acres. At the heart of the stations are huge solid-state valves known as thyristors, which convert ac to dc for long-distance transmission and then back to ac for feeding into the regional grid.



Itaipu converter station, Brazil



Thyristor valves at Comerford station, New England multiterminal project

ADVANCES IN HVDC EQUIPMENT

The evolution of HVDC systems has required significant developments in the technology of dc power conversion and transmission. Ongoing advances have reduced the costs of HVDC equipment, keeping the price roughly constant over the last 10 years, despite inflation. Such cost reduction is critical to more widespread use of HVDC transmission.

One of the most interesting technical processes in HVDC systems, and one in which EPRI has played an important role, is the conversion of ac power to dc and vice versa. This conversion is accomplished in a converter station. A converter essentially switches the dc current from valve to valve in a sequence, causing the dc current to flow as alternating blocks of positive and negative current into the ac system. Sequential firing of valves also simultaneously causes the portions of ac voltage to be arranged in a single rippling line of voltage.

The valves in converters act like one-way switches—when activated by firing pulses, they allow current to flow in one direction but block current flow entirely in the reverse direction. The earliest valves, developed in the 1950s, were high-voltage mercury arc devices, six of which were used (two per phase) to convert three-phase ac power into six pulses of dc. Solid-state valves, known as thyristors, were developed in the 1960s and have received extensive support from EPRI since its inception.

EPRI has also supported the development of digital controls that tell the thyristors when and in what sequence to fire, much as the distributor in an automobile engine controls the firing of the spark plugs. Thyristor valves have allowed modern converters to change from 6-pulse to 12-pulse firing, resulting in less distortion in the conversion process. In addition to handling valve firing commands, the digital controls modulate currents and voltages in the converter.

EPRI has also played an important role in the development of dc circuit breakers. In an attempt to keep costs low, the breaker designs that have resulted are built from standard, off-the-shelf components, such as interrupter modules, capacitors, and zinc oxide surge suppressors.

After five years of development, EPRI successfully field-tested two prototype dc breakers installed at the northern end of the Pacific Intertie in February 1984. After further upgrading, Brown Boveri Corp. recently tested its breaker at the company's research facility. The device successfully interrupted 4000 A of current at a system voltage of 500 kV. Moreover, the upgraded breaker clears line faults under these conditions within 30 ms, much faster than earlier designs.

The availability of reliable dc breakers is an important psychologic and practical factor for utilities considering multiterminal dc lines. Narain Hingorani explains: "Breakers are not absolutely necessary in multiterminal HVDC lines, but they can improve the system's performance by allowing faster clearing of faults and more rapid restoration of the unfaulted system. Now that the breakers are available, utilities can build multiterminal HVDC lines knowing that if conditions warrant, they can add breakers to the system at a later date."

Breakers and converters are not the only dc components that EPRI has been working on. Research has also been conducted on optimal strategies and materials for dc equipment insulation, better dc cables, improved designs for dc towers, and devices for locating faults. Fast and accurate fault location is particularly important on long-distance lines. A new system developed in a recent R&D effort uses a multichannel data processing system to collect voltage and current information 25,000 times a second. By measuring times between the multiple reflections of traveling waves produced by a fault, the new fault locater can be accurate to within one mile on a line spanning hundreds of miles without relying on any timing signal from the remote end, as was the case in the earlier version of the dc line fault locator.

Given the difficulty in siting new transmission lines, utilities are interested in sending as much power as possible through existing corridors. One way of doing this is to raise the voltage in the lines. No HVDC systems have yet been built to operate at a voltage higher than 600 kV, and most existing systems operate well below that level. EPRI recently funded an exploratory study to examine the potential for HVDC converters operating at 800, 1000, and 1200 kV. Although HVDC lines exceeding 600 kV are feasible, the study concluded that significant R&D would be needed to make such systems perform reliably.

Because HVDC systems involve relatively unfamiliar technology, utilities are cautious about building them. Consequently, the market for HVDC equipment, while improving, is quite modest at this point, and manufacturers are thus reluctant to devote extensive R&D to this area. "That's why EPRI has taken such an active role in HVDC equipment R&D," says Hingorani. "Our first priority is to attend to those things utilities need but will not get if EPRI doesn't do them." □

moved forward with the development of a digital computer program for integrating HVDC links into ac systems. The program allows planners to analyze whether or not various transmission system configurations will maintain stable operation in the few critical seconds following a disruption, like a generator tripping off or a line failing in a storm. The programs work by repeatedly calculating conditions throughout the system at very small time intervals—hundredths of a second—and assembling these separate snapshots into a moving picture of the system's response over time.

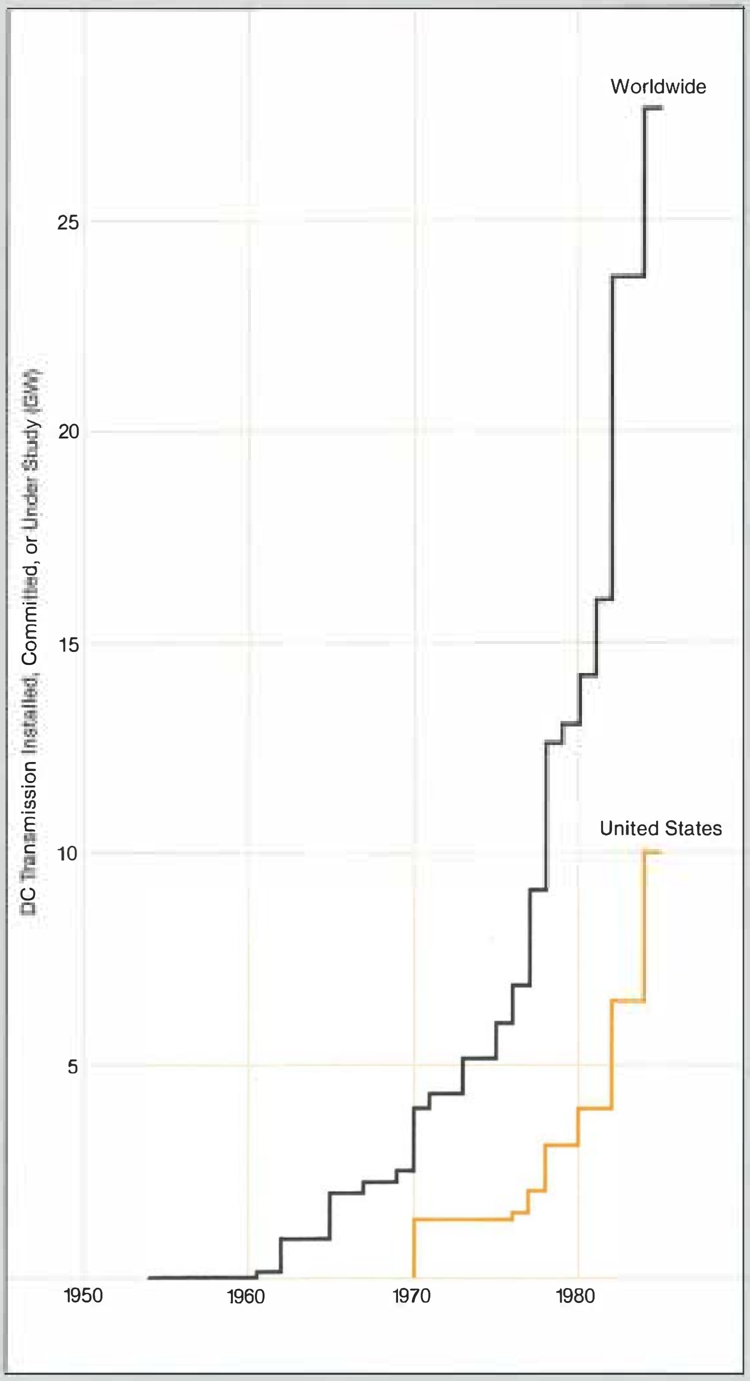
The program has a number of unique features that set it apart from other digital ac/dc programs. The key advantages are its flexibility and its ability to model very large systems (for example, the western interconnection ranging from the Rocky Mountains to the Pacific Coast has been modeled, using about 2000 nodes). Balu explains, "The program can model two-terminal and multiterminal HVDC controls, and it contains a flexible modeling capability, called user-defined controls. This feature is provided through a comprehensive set of control system modules that can be connected together in any configuration to model the desired control system."

Although the user-defined controls are very useful for studying specific system configurations, it is not always clear at the start of a project which controls should be modeled. In such cases, the user can still use the EPRI software by invoking a set of generic control configurations that are supplied with the model. This feature can save considerable time and expense in preliminary evaluation of dc control options.

Balu adds, "As far as we know, no other HVDC model has this user-defined control capability." It allows the user to simulate a wide variety of control configurations and to simulate equipment from different vendors. Previously, a utility that wanted to consider HVDC alternatives for which there was no existing analysis software had to develop a costly

Growth of HVDC

The economics, performance, and operational advantages of dc transmission have prompted tremendous growth of HVDC systems in the United States and throughout the world over the past quarter century. Recent competition in the electricity marketplace, based in part on the concept of wheeling bulk power considerable distances, is expected to boost utility interest in these systems even higher.



and time-consuming custom model for each different control setup and each different vendor.

Preliminary versions of the ac/dc program were completed in August 1985 and underwent extensive testing by two utilities now planning large HVDC lines—Manitoba Hydro and New England Electric. The host utility tests proved highly successful, and the program has been revised to incorporate their suggestions. The program will be made available through EPRI's software center late this summer.

A growing user group

The new software is already capturing the interest of a number of utilities. Balu reports that about 10 utilities expressed an interest in using the new HVDC software at a seminar on the models held in May of this year, several months before the package was due to be released. New England Electric is already using the models in planning for a five-terminal HVDC line. The first phase of this project will carry 700 MW through a two-terminal line directly from James Bay in northern Quebec to New England later this year. According to Gulachenski, "Not only will the models be useful in developing the multiterminal link with Quebec but we also expect to use them to study the system after it goes into operation."

The Los Angeles Dept. of Water & Power (LADWP) also expects to use the models. Bonneville Power Administration (BPA) and LADWP pioneered HVDC in the United States by building the first long-distance (846-mi, 1360-km) HVDC transmission line in the country, from Oregon to southern California. LADWP continues to pursue new applications of the technology, upgrading (jointly with BPA) the dc Pacific Intertie from Oregon, adding a new 486-mi (782-km) HVDC line (the Intermountain Project) from Utah to California, and conducting negotiations and planning studies with several other participants on a multiterminal HVDC system running from the Phoenix area to the Los Angeles basin, with a tap at Lake Mead. Arizona's Salt River Project is working with LADWP and the Western Area Power Administration on the multiterminal link.

According to Gary De Shazo, senior engineer, Salt River Project is also considering a direct HVDC intertie between the Pacific Northwest and the desert Southwest. "We expect to see more use of HVDC technology in the future," he explains, "for diversity exchange between areas with different seasonal peaks. The ac/dc programs EPRI has developed would be especially useful to us because of the flexibility offered by the user-defined controls."

System planners who have studied and worked with HVDC applications recognize the benefits of dc transmission. But many of their colleagues in the industry have not yet had the opportunity to explore HVDC options. This is why the new HVDC software tools are an important and timely contribution. Recently retired Electrical Systems Division Vice President John Dougherty comments, "The biggest hurdle of all is to make the planners aware of the possible benefits of dc transmission and to provide them with the tools they need to do side-by-side comparisons of all-ac and ac/dc systems. If their planning shows that ac is better for their system, they should go right on building ac. But if it shows dc links can help, they ought to feel confident enough in the availability of the equipment to go ahead and pursue the dc option."

A staunch advocate of HVDC, Dougherty nevertheless asserts that utilities should "retain the enormous benefits of the free-flowing ac network—the ability of systems to share energy back and forth automatically—while enhancing the system's stability and efficiency through strategically embedded dc links." Balu adds, "With the limited availability of transmission corridors and the ever-growing need to move power, the system is being stretched as never before, and greater emphasis is being placed on the potential of HVDC technology. We believe that our computer programs will provide transmission planners with the information and confidence they need to consider HVDC links as a viable option in their planning." And so the debate between ac and dc has come full circle. Thomas Edison, who thought he lost this battle a century ago, would be pleased.

Further reading

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This article was written by Michael Shepard. Technical background information was provided by Neal Balu, Electrical Systems Division. Additional information was provided by Robert Iveson and Narain G. Hingorani.

Fleet Vans Lead the Way for Electric Vehicles

Targeted for the fleet vehicle market, with its unique economics and service infrastructure, electric vans now seem ready to break through the barrier of commercial acceptance.

American service fleets employ approximately 2.4 million vans for tasks ranging from transporting utility repair crews to delivering flowers and pizzas. In the near future, these fleets are likely to use an increasing number of electrically powered vans that will run more cheaply, cleanly, and quietly than their internal combustion engine counterparts.

Since the mid 1970s, when the electric vehicle (EV) reemerged as an appealing transportation option, developers have recognized the commercial potentials of electric fleet vans. Because the vans are battery-powered and require regular recharging, they are well-suited to the short routes and regular schedules followed by most vans in service fleets. Many fleet operators, as shown in demonstrations, can fully recharge electric vans at night or during other off hours.

Developers have also recognized the potential of electric fleet vans as cost-competitive alternatives. Fleet operators are generally concerned with the life-cycle costs of their vehicles, which must be fueled and maintained through years of service. These concerns work to the advantage of electric vans, which—in spite of initial costs higher than those for conventional vehicles—promise savings on fuel and maintenance over vehicle lifetimes.

Following this logic, researchers in federal, industrial, and utility-sponsored projects have worked over the past 15 years to design prototypes for increasingly more capable and cost-effective electric vans. Swiftly and without a great deal of publicity, progress has been made in EV battery systems, in other propulsion components, and in the integration of different systems into complete van designs. Recently, many of these advances have been incorporated into the first commercially viable production EV to arrive in North America—the General Motors Griffon.

The Griffon is an electric service van, and it is the first vehicle to be manufactured as such on the assembly line of a major manufacturer. Produced in England by Bedford Commercial Vehicle Division of the General Motors Overseas Commercial Vehicle Corp., the Griffon is known as the Bedford in Europe. About three hundred of these Griffons/Bedfords are already in service under government subsidies in Europe, handling missions like carrying passengers between airport terminals and delivering the mail.

Now available in limited quantities to commercial U.S. operators, the Griffon drives faster, accelerates better, and ranges farther than any of the experimental vehicles that were frequently demonstrated at utility sites in the 1970s. With mass production in coming years and with the addition of technology improvements now in development, electric vans like the Griffon are expected to emerge as cost-competitive service vehicles by the end of this decade.

Utilities leading the way

In concert with the arrival of the Griffon, the electric utility industry has recently increased its support for technology and technology transfer programs that focus on electric vans. Because these vans and other EVs are often recharged at night, they promise electric utilities a major new source of off-peak demand. This new demand, studies show, can probably be served through the end of the century without the addition of any new capacity. At the same time, EVs run cleanly and burn no gasoline, promising benefits to both the national balance of trade and the natural environment. Add the fact that EVs present utilities with several business opportunities apart from the rate base (e.g., vehicle leasing, vehicle servicing, and recharging facilities), and it becomes clear that electric utilities have many good reasons for giving EV technology a forward push.

In the area of technology transfer, this push is currently centered in the Electric Vehicle Development Corp. (EVDC), Cupertino, California, a utility-directed organization that is tackling the problems inherent in developing markets for electric vans. Formed in 1983 by a group of investor-owned and public utilities, the nonprofit corporation is taking a phased, gradual approach to EV technology transfer, starting with the nation's service fleets.

"In themselves, service fleets offer a significant market to both the electric utilities and the vehicle manufacturers," states Gerald Mader, EVDC's president. "At the same time, the fleets represent a foothold for all EV technology, a first chance to introduce the public to the concept, accumulate operating experience, and establish an infrastructure that an expanded industry, including future EVs for personal use, will require."

With these goals in mind, EVDC is currently concentrating its resources in the Electric Van Demonstration Project, a multiyear effort that will support the deployment and operation of the Griffon in the service fleets of utilities and other industries. Distinct from many of the EV demonstrations of the 1970s, the EVDC project involves the participation of an automobile manufacturer (General Motors) and subsystem suppliers, likely stakeholders in a future EV industry. Moreover, the project is the first of its kind to feature a commercially viable production vehicle.

"We are not asking the project participants to operate a conventional vehicle that has been converted for use with an EV battery," explains Gerald Mader. "Instead, we're working with a production EV already in service in Europe, and we're backing it up with the propulsion system vendor and vehicle manufacturer services that commercial operators depend on."

The development of a service infrastructure, as Mader explains, is a crucial aspect of the project. If an EV market is to succeed, the public will need access to special parts inventories and to mechanics who can repair EVs. Through the EVDC project, General Motors and the propulsion system vendor have established networks for these services on a small scale and will gradually expand their services as the market grows. Meanwhile, project workers will be gathering data from the van fleets where the Griffon is deployed. Their analyses of the economics and the day-to-day problems encountered in operating EVs will be used to make service and vehicle improvements.

Intensified technology programs

Complementing the activities of EVDC, EPRI intensified its Electric Transportation Program in 1985 to emphasize the development of components and systems for electric vans. EPRI is also working in concert with DOE, which maintains its own program in EV R&D.

"The federal program has created a powerful momentum toward the commercialization of electric service vans," states David Douglas, manager of EPRI's program. "We've revised our program to help sustain this momentum and to complement DOE in key areas of technology."

EPRI's current technology plan is designed to follow three convergent tracks: vehicle systems development, including support for EVDC; battery systems development; and propulsion systems development. At the center of these efforts is a multiyear joint project with DOE to develop prototypes for improved electric vans. Begun in 1985, the project will extend through the design, fabrication, and evaluation of electric vans expected to be competitive with conventional vans on the bases of short-range performance and life-cycle cost. Incorporating battery and propulsion systems developed in other areas of the DOE and EPRI programs, the first of these improved vans could serve as a prototype for commercial fleet EVs that could be produced in limited quantities by 1987–1988. EPRI plans to follow the improved van in the early 1990s with an advanced van that will include battery and propulsion systems that are in early phases of development today.

While EPRI and DOE work toward prototypes for improved electric vans, the Griffon provides a benchmark for assessing the capabilities and cost-competitiveness of commercially available technology.

As the centerpiece of EVDC's electric van demonstration project, the Griffon has undergone rigorous performance evaluations at both TVA's EV Test Facility and EG&G's Automotive Research Center in Idaho Falls, Idaho. At the two sites, Griffons were subjected to track, dynamometer, and road testing, with tests designed to measure performance under both urban and highway driving conditions.

Test results confirmed that the Griffon is a reliable and traffic-compatible van, entirely adequate on the basis of its performance for the work missions of many fleet vans. With a top speed of 50 mph, the Griffon can travel 55–60 mi (88–97 km) in urban conditions before requiring a recharge. Although this limited range, a crucial EV performance factor, might make the Griffon unsuitable for long-distance hauling and for many kinds of personal vehicle use, fleet operators are usually able to recharge EVs at night or during other off hours. Similarly, the Griffon's respectable top speed and somewhat limited powers of acceleration (0–30 mph [0–48 km/h] in 11 seconds) are not incompatible with everyday tasks in most service fleets.

Becoming cost-competitive

A more central concern to fleet operators is the comparative cost of owning and operating conventional and electric vans. On the basis of initial or capital cost, electric vans (largely on account of their expensive batteries) are likely to cost more than conventional vans for decades to come. In 1985 the Griffon, a rare beast, cost more than $20,000, about twice the price of a standard conventional van. As a result of production increases, the 1986 price will be 10–15% lower, and mass production in the United States could lower the purchase price further before the end of the decade. Nonetheless, the Griffon—and any comparable electric vans that may appear—are still certain to cost at least 30% more on purchase than the conventional vans of the 1990s.

By that time, however, comparatively lower operating costs should outweigh the larger capital outlays that electric vans require. EV operators must sustain three major operating costs—battery recharging, vehicle maintenance, and battery replacement—but these costs (over a vehicle's lifetime) are significantly less than the gasoline and maintenance bills incurred by conventional vans.

The Griffon's 216-V lead-acid battery costs more than $4000, approximately 20% of the capital cost of the entire vehicle. Warranted for four years, the battery is likely to need replacement during the van's operating life. Furthermore, the electricity stored in the Griffon's battery must be replaced after every 55–60 mi of service. EVDC calculations show electricity at an average off-peak rate costing fleet operators about 4.5¢/mi. By comparison, gasoline, even if its price dips periodically through the end of this decade, will remain a costlier source of energy. Even at gas prices as low as 85¢/gal, fleets operating vans face fuel bills that average approximately 8.5¢ per service mile—nearly twice the likely cost of electric power.

Internal combustion engine vehicles (ICEVs) also require more maintenance over their lifetimes than do the batteries and electric motors of electric vans. It barely needs mentioning that ICEV engines contain many moving parts that are constantly vulnerable to corrosion, fouling, high temperatures, and various mechanical stresses. EV batteries and motors, by comparison, involve no explosive fuel and very few moving parts; on average, they are about half as costly as conventional vans to maintain over their lifetimes.

When operating savings on fuel and maintenance are balanced against initial costs and the cost of battery replacement, the 1986 Griffon will nearly break even with conventional vans on a life-cycle basis. With capital costs going down, and with new technologies promising battery systems that require less maintenance, there is little doubt that electric vans like the Griffon will be fully cost-competitive with conventional vans by 1990 or sooner.

The battery alternatives

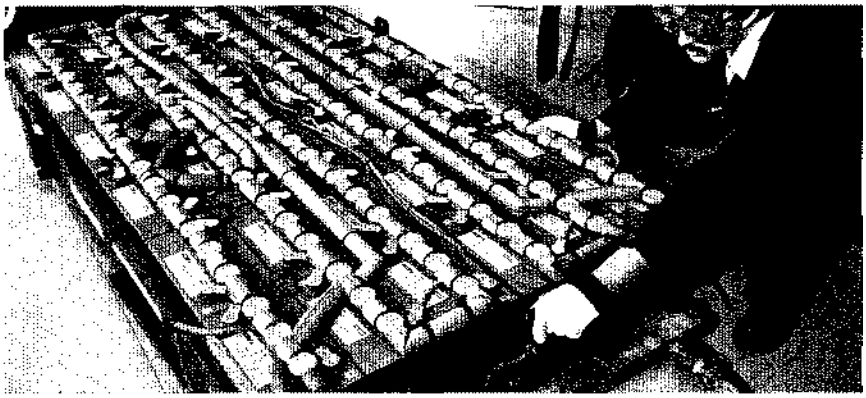
Looking to make electric vans increasingly more capable and cost-competitive, researchers in EPRI and DOE programs are focusing on the EV battery—the most costly component in the vehicles, as well as the most important to performance.

The suitability of batteries to commercial electric vans is reflected in a series of different parameters. Most significant are cycle life (the number of times a battery can be charged and recharged before it wears out) and specific energy (the ratio of usable energy to battery weight). Improvements in battery cycle life are expected to reduce costs for battery replacement over the lifetime of an EV. Batteries with higher specific energy can help electric vans and other EVs range farther, expanding possible applications.

Researchers are thus balancing specific energy and cycle life against other factors, such as maintenance requirements, vehicle safety, manufacturing costs, and the battery's specific power (the determining factor in the EV's ability to accelerate and climb hills).

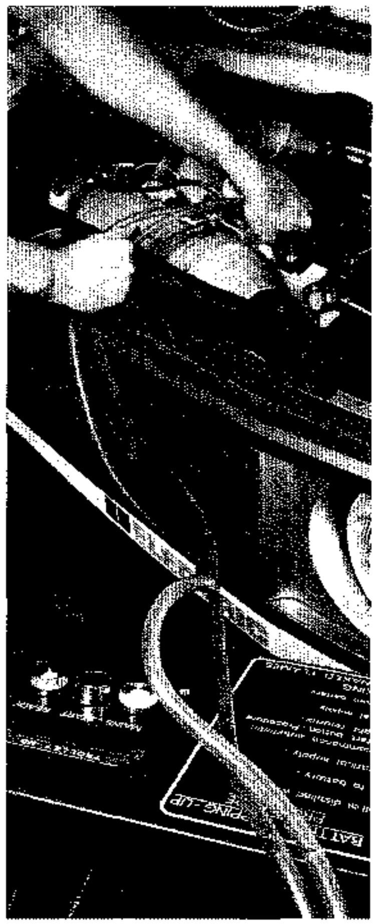
Working with TVA, EPRI is conducting in-vehicle field tests of several different near-term battery systems, including lead-acid, nickel-iron, nickel-zinc, and nickel-cadmium. Data from these tests will be evaluated in the selection of the best available battery for use in the improved van that EPRI is developing with DOE. Ironically, the baseline battery is also the oldest—the lead-acid battery. A fixture in EVs since the turn of the century, lead-acid batteries, such as the system in place in the Griffon, are still offering the best commercially available mix of economy, safety, and performance.

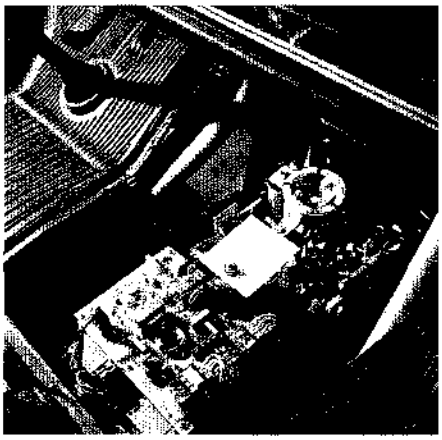
In the advanced battery area, EPRI-



Battery pack

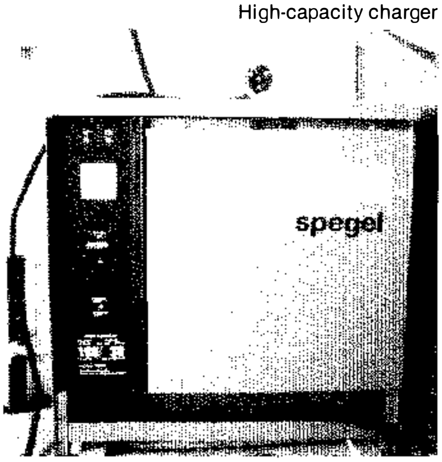
Watering unit





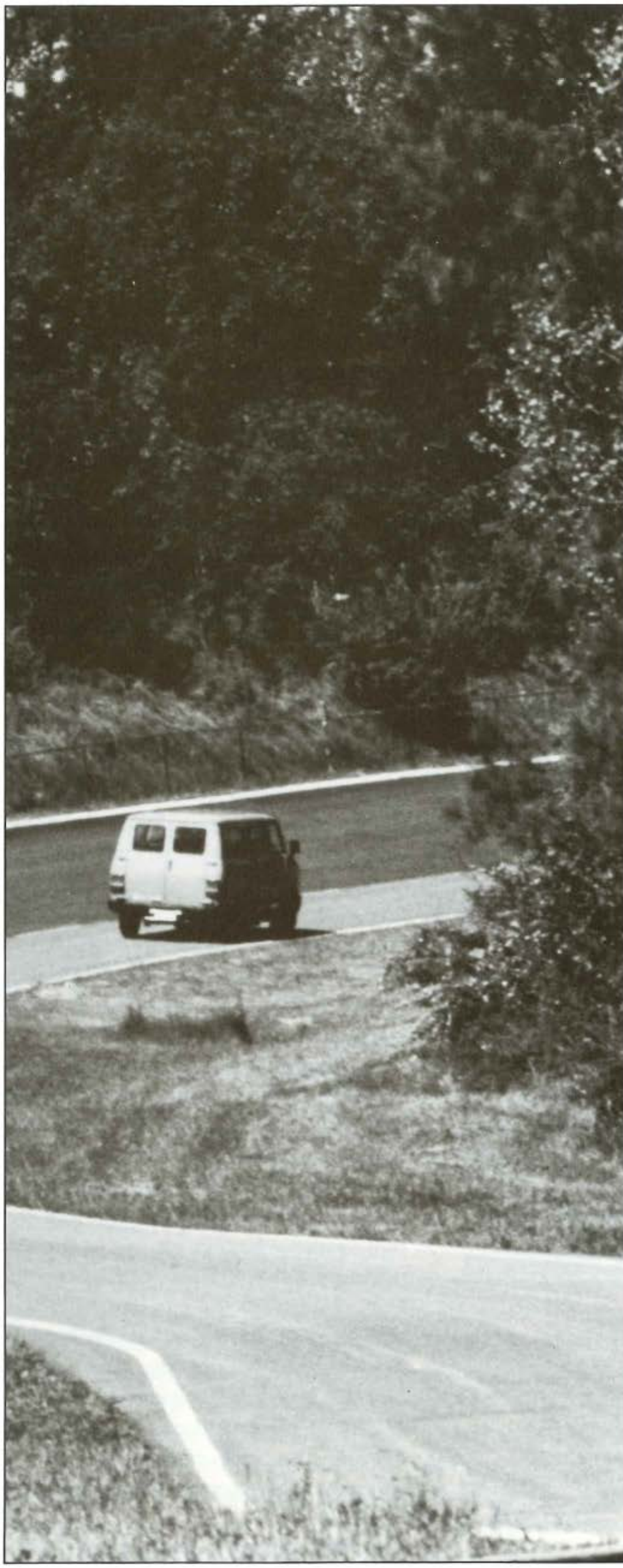
Electric controller

High-capacity charger



Inside the Fleet Van

The Griffon's internal components were designed specifically for trouble-free operation and easy maintenance, as confirmed in field evaluations at Detroit Edison Co. and five other utilities. An electric controller, which regulates the current flowing from the storage batteries to the drive motor, provides smooth acceleration without a transmission. Because the van is powered by an electric motor, there is no engine oil, transmission fluid, coolant, or clutch. Routine maintenance is confined primarily to topping the battery water levels every three weeks by means of a portable, self-regulating unit that plugs right into the battery pack. The battery itself is normally charged overnight with a high-capacity charger that connects to terminals in the vehicle; the entire battery tray can be easily removed from under the van's midsection to test or change individual battery modules.

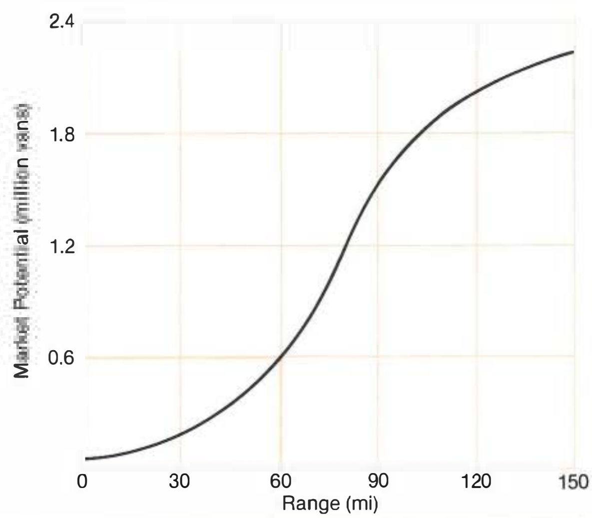


Specifications for the GM Griffon

Top speed	53 mph
Range	55-65 miles
Acceleration to 30 mph	11 seconds
Braking (from 30 mph)	51 feet
Battery life	4 years
Energy consumption	0.9 kWh/mile
Load space	208 cubic feet
Payload	1900 pounds
Length	174 inches
Width	89 inches
Height	79 inches
Wheelbase	106 inches
Curb weight	5800 pounds
Gross vehicle weight	7700 pounds

The Market for Electric Vans

Increasing the distance that an EV can travel on a single charge is the most significant factor in expanding the market for electric vans. The 60-mi (97-km) range of the Griffon makes it a replacement candidate for about 600,000 commercial fleet vehicles now operating in the United States. If advanced batteries doubled the vans' range to 120 mi, the potential market for these vehicles could top two million.



supported researchers at Gould, Inc., and DOE's Argonne National Laboratory are investigating the potential of a lithium–iron sulfide battery. This battery has demonstrated a specific energy well beyond that of the lead-acid battery in the Griffon. Work remains to be completed, however, before its cycle life and initial cost can be shown to be comparable to the baseline. The same uncertainties surround another high-energy alternative, the sodium-sulfur battery, which EPRI research managers hope to subject to in-vehicle field tests in 1987–1988.

Because of their high specific energy and power, these advanced battery technologies promise significant improvements in the range and acceleration of future EVs. They are thus prime candidates for use in EVs that will be suitable for both an expanded range of service applications and many kinds of personal use.

An advanced battery that may prove to be of more immediate value in fleet vans is the sealed lead-acid battery, one version of which is now under development in an EPRI-sponsored program at NASA's Jet Propulsion Laboratory (JPL) in Pasadena, California. If successful, it will eliminate the need for fleet operators to regularly add water to their EV batteries. Though watering would not seem to be a significant maintenance requirement, it consumes man and vehicle hours and can cause serious problems if neglected.

The promise of ac propulsion

Another area of EPRI EV R&D, also under way at JPL, focuses on the development of electronically controlled drive train systems, including ac induction motors that are some 75% cheaper and 50% lighter than comparably powerful dc motors. These drive systems employ state-of-the-art transistors in small, lightweight power inverters that change the battery's dc power into ac power for the motor. The inverter, along with a small microcomputer, form a controller that responds to the driver's pressure on the vehicle's acceleration and brake pedals.

Electronically controlled ac drive systems are now just a few years away from integration into designs for complete EVs, including the advanced vans that EPRI expects to be built in the early 1990s. Studies based on currently available technology show that the replacement of bulky dc motors and chopper controllers with a significantly cheaper system of computer, inverter, and ac motor could lower the initial cost of vehicles like the Griffon by 9–11% without reducing the vehicle's range. If the designer wishes to take advantage of the ac propulsion system to affect range while holding costs constant, a range increase of 10–13% is achievable.

Looking for systems that offer the best possible balance of range and cost improvements, EPRI is also monitoring the ambitious ac propulsion projects being sponsored by DOE at Ford Motor Co. and Eaton Corp. In 1988 EPRI expects to select the best available system for integration with one of the advanced batteries under development in concurrent EPRI–DOE projects. The resultant propulsion system (drive train system and battery) will be incorporated in an advanced van.

Developing the market

While technology improvements and increased production lead to improved vehicles, EVDC plans to keep pace in coordinating the development of a North American market and service infrastructure for electric fleet vans. During 1985 a total of 29 Griffons were delivered to the service fleets of six U.S. utilities, beginning the field evaluation and infrastructure development phase of EVDC's General Motors Electric Van Demonstration Project. In early 1986, two additional vehicles were delivered to a participating Canadian utility.

As part of this phase of the EVDC project, General Motors and Lucas Chloride EV Systems, the propulsion system supplier, have established a centralized service and support system that includes a General Motors parts supply system, service and training manuals, and unprecedented warranties of four years on the EV battery and one year or 12,000 miles on the Griffon's mechanical parts.

This phase of the program will also feature extensive market research. Staying in close communication with the participating fleet operators, EVDC will collect and analyze vehicle operating data. Special attention will be given to needs for improvements in the Griffon and in the new service system, as well as to the identification of potential markets for electric vans outside the utility fleets. In keeping with these goals, participating utilities are establishing promotional programs in which Griffons are leased to private commercial fleets.

In a third phase of the project, scheduled to begin in July 1986, up to 200 Griffons will be deployed at from 10 to 15 utility sites, and utilities will begin actively marketing the vans for use in other fleets in their service territories. Throughout 1986 and 1987 EVDC will work with the participating utilities to implement a program of user incentives, such as battery leasing arrangements and preferential electricity rates for EV operators.

The final phase of the project, expected to extend through 1988, will involve negotiations between the participating manufacturers, systems vendors, and R&D organizations to arrange the production and distribution of a van built in America. At this writing, EPRI is talking with General Motors about conducting a feasibility study for modification of a General Motors van to electric propulsion for production in the United States. Limited production could begin in 1988 on a van that would incorporate improved technology and offer performance improvements over the current Griffon model.

Questions for the future

The schedule for wide public acceptance of electric vans and other EVs is difficult to predict. The success of advanced bat-

Comparing Costs

The capital cost of current-generation electric vans is considerably higher than that of gasoline-powered vans. However, the bottom line for fleet vehicles is life-cycle cost, where the low maintenance and fuels costs characteristic of EVs can make a tremendous difference. A comparison of a conventional van with a state-of-the-art electric van like the Griffon shows total life-cycle costs over an eight-year period to be about equal when electricity is priced at 5¢/kWh and gasoline at $1.15/gal.

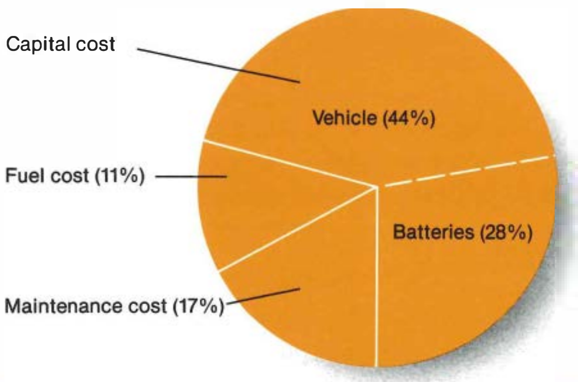
	Electric Van	Conventional Van Case 1	**Case 2**	Case 3
Assumptions				
Van cost[1]	**$19,300**	$12,100	**$12,100**	$12,100
Replacement battery	**$4,750**			
Fuel consumption	**0.9 kWh/mi**	10 mpg	**10 mpg**	10 mpg
Fuel cost	**5¢/kWh**	$1.00/gal	**$1.15/gal**	$1.25/gal
Salvage value	**20%**	15%	**15%**	15%
Battery salvage value	**5%**			
Life-Cycle Costs (¢/mi)				
Depreciation				
Vehicle	**13.5**	11.7	**11.7**	11.7
Battery[2]	**10.0**			
Cost of capital[3]				
Vehicle	**4.4**	3.6	**3.6**	3.6
Battery[2]	**1.4**			
Fuel/electricity	**4.5**	10.0	**11.5**	12.5
Maintenance	**7.0**	14.0	**14.0**	14.0
Total cost (¢/mi)	**40.8**	39.3	**40.8**	41.8

[1]Assumes U.S. manufacture. Cost of imports will be affected by import duty and currency exchange rate.

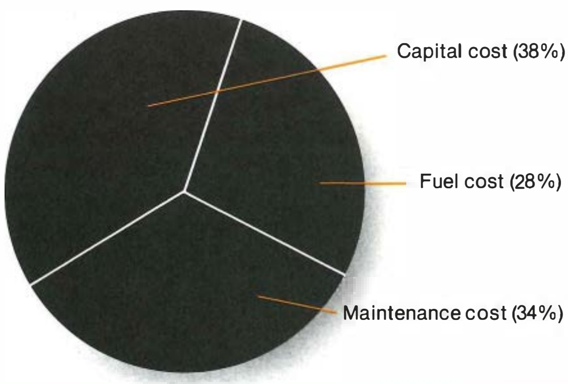
[2]Includes replacement of the battery after four years.

[3]Real cost of capital assumed to be 6%/yr.

Electric Van (Life-cycle cost = 40.8¢/mi)



Gasoline-Powered Van (Life-cycle cost = 40.8¢/mi)



teries now in development will be important in expanding EV range and, in turn, the markets for both commercial and personal-use EVs. At the same time, the cost of gasoline is likely to have an effect on the rate at which the market for electric vans and other EVs develops in the United States. Regardless of gasoline prices, electric vans will soon be cost-competitive alternatives to conventional vans. Higher gas prices, however, will help acquaint the public with a technology that is still unfamiliar to most Americans.

A recent independent review for EPRI of EV market projections helps to narrow the uncertainty somewhat. Covering some 20 separate studies, this review was based on gasoline prices at $1.25 in 1980 dollars, a four-passenger EV with a 100-mi (160-km) range in existence by 1990, and the use of EVs only as second cars for personal use. In its own review, EVDC adjusted these assumptions to make the 100-mi range EV a reality in 1995. EVDC projections now point to about seven million EVs on American roads by 2005, with about two million electric service vans in use. After the turn of the century, according to these same estimates, a million new EVs might be purchased each year until 2010. Beyond that point, the market is likely to expand even faster, with the availability of gasoline the most important factor in its growth.

This movement toward electric transportation is almost certain to have a positive effect on the utility industry, as well as on society as a whole. The recovery of some of the billions of dollars that leave the country annually to pay for imported oil is likely to provide a powerful stimulus to the national economy. If just 25% of the miles driven by conventional vehicles are replaced by EV mileage, the country could save more than two million barrels of oil a day.

At the same time, a switch toward EVs will reduce hydrocarbon and carbon monoxide emissions in urban environments where traffic is dense. Electricity generating plants produce emissions of their own, but EVs will not require new generating capacity for decades to come. Even in a hypothetical and highly unlikely situation in which half of all vehicles with internal combustion engines are replaced by EVs, a situation in which capacity problems might result in some utility service areas, the nationwide effect of vehicle electrification would be substantially cleaner air.

The more likely scenario, as the projections show, is a gradual shift toward EVs in many different commercial markets, beginning with van fleets and expanding to light trucks and passenger cars used for short-range driving. Other electric transportation alternatives, such as hybrids (combining EV batteries and internal combustion engines in the same vehicles) and different types of mass transit systems, are now being studied by EPRI for their potential role in a shift away from burning gasoline in the approximately 150 million vehicles on American roads.

EPRI studies based on an average electricity use of 30 kWh/d per vehicle show a nationwide distribution of just two million EVs producing an annual electricity demand of 21.94×10^9 kWh. If these figures are applied to EVDC's most conservative estimates of market growth, utilities will earn some $35 billion from EVs between 1990 and 2010 with virtually no new capacity required. EVDC calculations based on the same estimates of EV electricity requirements show that utilities could employ the existing and underused capacity of high-efficiency baseload plants to supply power to as many as 7.5 million EVs. Though capacity problems could conceivably occur in some local areas, the industry as a whole will not need new capacity to serve EVs in this century.

According to a recent EVDC analysis of existing market projections, the low cost of supplying electricity to EVs will make it feasible for utilities to apply time-of-use rate structures as incentives for EV users. By charging less for nighttime recharging, EVDC concludes, utilities should be able to effect both further reductions in EV operating costs and further expansion in the market for EVs. ■

Further reading

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This article was written by Jon Cohen, science writer. Technical background information was provided by David Douglas and Lawrence O'Connell, Energy Management and Utilization Division.

Electric utilities increasingly encounter the need to cut costs and reduce financial risks; therefore they require better planning tools to help balance conflicting priorities. Uncertain load growth, fluctuating fuel prices, changing environmental protection requirements, and such new options as demand-side management opportunities must all be considered in the planning process. At the same time, utilities are also under mounting pressure from the regulatory agencies to demonstrate that their previous planning decisions were financially prudent and their current planning decisions represent a least-cost strategy for consumers. Improved planning tools can help the utility planner develop a deeper understanding of future conditions, while allowing for mounting uncertainties.

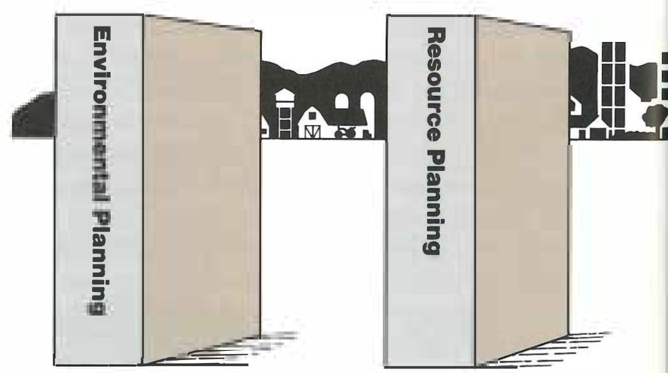
EPRI is developing a wide variety of computer programs that utilities can use in making planning decisions at every level of their operations. Analysts for top executives can employ corporate planning and financial management codes to model a whole utility system for periods of 20 years or more and quickly find answers to numerous "what if" questions. Additional computer programs are now available for forecasting electricity demand while incorporating the effects of demand-side management programs. Resource and generation planning are made easier by codes that compare both conventional and alternative energy options, improve fuel management, account for environmental trade-offs, and incorporate system reliability considerations. And computer models of transmission and distribution systems enable utilities to make more-effective decisions about when to buy versus build, where to locate facilities, and how to maintain system reliability. The computer tools developed by EPRI, however, constitute only a fraction of the analytic capability required by the electric utility industry. Each utility will undoubtedly be interested in different sets of tools that complement the software it has already been using.

Corporate planning and decision making

Although computer models have long been used by utility planning departments, their importance to other utility decision makers is now growing rapidly. As load growth has become more uncertain, utility executives have adopted new business strategies to lower the risk exposure. These place more emphasis on demand-side management, plant life extension, better fuel procurement, more-effective use of the power system, and careful planning of expenditures in general. Such initiatives require the availability of flexible analytic tools that can integrate existing system planning and operating tools with the new strategies.

Having made the necessary strategic decisions, executives must also be able to satisfy regulatory agencies that increasingly demand a more formal assessment of utility decisions. To incorporate funds for construction work in progress into a

Modern utility planning is complicated by the interplay of institutional, economic, and technical decisions that must be made at different levels in the organization. EPRI planning software can be an important complement to a company's own store of decision-making tools.



The Utility Planner's Library

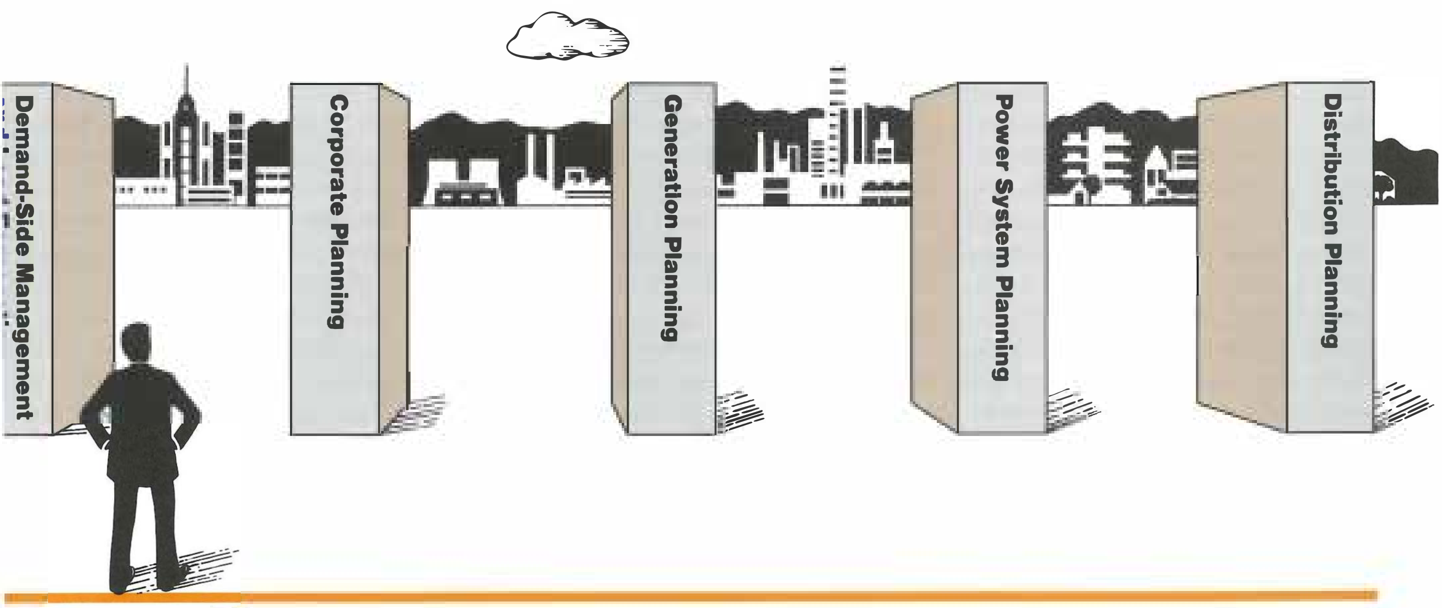
utility's rate base, for example, the Federal Energy Regulatory Commission now requires the utility to "include an assessment of the relative costs of adopting alternate strategies and an explanation of why the program adopted is prudent and consistent with a least-cost energy supply program."

EPRI's utility planning model (UPM) is designed to provide utility executives with the analytic capability to make long-term financial decisions and rapidly prepare the needed support documentation. UPM simulates the major functions considered in utility planning: load forecasting, system planning, production costing analysis, fuel supply planning, financial analysis, and rate and revenue analysis. Such simulations are based on data from more-detailed analyses made in the respective functional areas.

UPM has the degree of flexibility necessary to tailor the model closely to an individual utility's financial structure, regulatory jurisdictions, and financial planning problems. In one of the code's first major applications, Commonwealth Edison Co. used UPM to produce 20-year estimates of cash requirements and electricity prices for the Illinois Commerce Commission. UPM also enabled Commonwealth Edison to screen ideas on incorporating new nuclear units into the rate base in a way that would moderate their effect on customers and to prepare documentation in support of the company's submissions to the Illinois Commerce Commission.

One of the most important uncertainties that drives utilities' strategic and financial planning is the question of load growth. EPRI's OVER/UNDER model helps utility planners evaluate capacity expansion alternatives by balancing the cost of planning too much capacity against the risk of planning too little, while taking account of uncertain load growth explicitly. A distinguishing feature of the OVER/UNDER code is that it calculates long-term costs and benefits of alternative capacity reserve margins from the point of view of both utilities and their customers. The model has been applied at utilities that collectively serve well over one-half of the nation's electric load. The applications of OVER/UNDER have figured prominently in numerous regulatory proceedings.

A more specialized model, TELPLAN, is designed to help utilities incorporate a variety of environmental factors into their long-range planning. This code analyzes the effect of environmental emissions, regulations, and controls on total production costs, using a very detailed treatment of individual generating plant characteristics. These costs are then incorporated into the financial statements and statistical reports generated by this



Software for Hard Decisions

model. Because of its computing speed, TELPLAN has been used by Consolidated Edison Co. of New York to analyze hundreds of planning scenarios involving a variety of generation options and environmental constraints. The company found that simulations requiring seven days with other programs could be performed in one day with TELPLAN.

Environmental analysis

Having developed strategic plans for capacity expansion and reliability, utilities have to evaluate the effect such plans will have on the environment, public health, and the economic well-being of the company. Strategic plans must also be consistent with changing environmental regulations and evolving issues. Therefore, EPRI has developed a number of models to help utility planners deal with complex environmental issues.

Utilities are very interested in finding cost-effective strategies for reducing environmental impacts. ADEPT is a decision framework for comparing alternative strategies to reduce acid deposition in light of the many scientific uncertainties about the efficacy of controls and the potential for severe ecological damage. In addition, three codes are now available to deal with concerns over PCBS: TRIM can estimate the costs and benefits of alternatives to protect the public health and environment from utility equipment containing PCBS; COIL can be used to assess strategies for sampling mineral oil transformers for PCBS; and ASK offers power plant managers help in managing the economic risks of high-cost PCB incidents.

There are a number of EPRI codes that characterize the physical environment. ILWAS is a detailed simulation model that predicts changes in lakewater acidity resulting from changes in acid deposition. MYGRT evaluates the migration of solid wastes in groundwater and can be used as a screening tool for selection of disposal sites and technologies. Two other codes can be used in evaluating specific environmental conditions. EPAM analyzes aquatic monitoring programs for thermal power plants, and EXPOCALC calculates electric field values around transmission lines.

Demand-side management and load forecasting

Conflicting trends, such as rising fuel prices, low load growth, and the potential need for electric power to improve productivity through the introduction of more-efficient industrial processes and automation, make energy and load-shape forecasting increasingly difficult. Planners can benefit from models that analyze the end-uses of electricity in detail.

Utilities also have more ways now of better matching supply and demand. For instance, in addition to building new power generating facilities, they can institute such demand-side management programs as strategic conservation and load-management programs or buy more power from cogenerators. These activities require analytic tools to strike a balance among various demand-side options, increase the value of electricity, and preserve the reliability of electric service.

The complementary use of multiple computer programs is an important consideration that has guided EPRI software development in this area. Sierra Pacific Power Co., for example, was able to combine three EPRI codes with some of its own computer programs to form a single forecasting package. REEPS was used to model residential end-use patterns of electricity consumption, and COMMEND was employed for commercial end use. The output from these programs was then fed into HELM to produce an hour-by-hour electric load shape forecast for a whole year. REEPS and COMMEND can create very detailed projections of electricity consumption at the end-use level because they disaggregate important variables and emphasize customer decision making. HELM is a tool that enables a utility to make detailed load-shape forecasts over a long period (10–20 years) and for any number of customer groups. Similar codes are being developed to provide load and load-shape forecasts for the industrial and agricultural sectors.

Several EPRI computer programs help utilities weigh the costs and benefits of various demand-side management options. The most comprehensive of these codes is LMSTM, which is designed to help a utility compare the advantages and disadvantages of demand-side management directly with supply-side alternatives. The components of LMSTM can explicitly account for such demand management programs as direct load control, thermal storage and time-of-use pricing, as well as a variety of supply-side options, among them conventional and alternative generation technologies, central station energy storage, and power purchases. After Sierra Pacific Power Co. computed a detailed load forecast with HELM, 31 demand management options were evaluated with LMSTM.

Analysis of many demand-side management options involving residential and commercial loads requires an engineering analysis of the building structure and thermal factors. EPRI has developed a few codes in that area. LOADSIM, for example, models the effect of load management options on utility load shape by simulating heating, ventilation, and air conditioning demand for a single house, taking weather and building characteristics into account. This approach enables a utility to study the effects of load management strategies for individual types of homes. On a more detailed level, EMPS and ESPRE simulate residential heating and cooling loads in a way that allows a utility to evaluate specific conservation measures and appliance configurations.

Three EPRI codes help utilities and their industrial/commercial customers determine the cogeneration system that will be most beneficial to each. DEUS was developed to evaluate the cost, design, and performance of site-specific cogeneration systems. It incorporates several specific cogeneration system designs internally, takes into account projected load profiles for both steam and electricity, and computes cost information, rates of return, cash flows, and so forth. COPE uses the cost and performance data developed by DEUS (or similar codes) to evaluate the effect on a utility of various cogeneration financing and ownership arrangements. COGEN3 analyzes specific cogeneration projects to determine the optimal design and operating schedule that can meet the steam and electricity requirements at lowest cost. Other codes are under development to assess industrial park cogeneration systems.

Generation planning

For optimal planning, a utility considers new generation capacity additions along with demand-side management options. Generation planners need tools that not only help select the optimal level of capacity expansion but can analyze an increasingly wide variety of generation technologies, while taking into account existing demand-side options and various environmental and financial constraints.

EPRI's most comprehensive generation expansion model is EGEAS, which incorporates three previously separate stages of analysis into a single integrated package. In the first of these stages, the code takes a load forecast and calculates a utility's optimal generation expansion. Second, it determines which expansion schemes will produce acceptable levels of generation reliability. Finally, EGEAS analyzes the cost of power production, including not only the new capacity additions, but also load management initiatives and intersystem purchases. EGEAS uses advanced algorithms to speed computations that can explicitly account for uncertainties in future fuel prices, capital costs, storage, and demand growth.

A utility planner can also use the technology choice model (TCM), a decision analysis approach, to compare different generation technologies according to their respective economic advantages, social and environmental impacts, and health and safety considerations. The TCM code can also be used in conjunction with a general-purpose decision tree evaluation program, DETGEN, to determine the probable effect of sequential decisions and uncertainties that will be resolved as a project continues. The economics of new technologies can also be screened with a computer program such as COMPETE, which is especially valuable in situations where the costs of particular fuels are escalating at different rates.

Resource planning

Fuel requirements generally represent about one-third of total utility costs; thus improved fuel management is a particularly important concern of the resource planner seeking to lower the cost of electricity production. Coping with changing costs and uncertain supplies of a fuel over the next several decades is one of the most challenging tasks facing utility decision makers.

EPRI codes on fuel planning have concentrated primarily on decisions about fuel procurement and fuel inventory management. CONTRACTMIX, for example, analyzes specific fuel contracting arrangements for coal, oil, gas, or uranium, taking into account the uncertainty of fuel burn and the variability of fuel prices. From CMCM a planner can obtain a preliminary estimate of coal mining costs, based on general site conditions and the type of equipment to be used. RRCS computes an estimate of the time, cost, and energy use involved in transporting coal to a power generating facility by rail over various routes. The detailed data on rail routes and costs are built into the model. CPCM determines the cost of coal cleaning and estimates the capital and operating expenditures needed to establish a coal preparation plant. This code also provides an interface file so that the computer information can be used with the CMCM code.

UFIM helps a utility determine the best level of fuel inventory at each plant by balancing the costs of holding fuel against those of encountering shortages. The code incorporates specific system characteristics and can consider uncertainties in fuel delivery, fuel burn, and various seasonal factors. Two utility case studies have recently demonstrated the potential value of UFIM: Consumers Power Co. used the code to estimate the inventory levels, taking into account the effect of cold weather in winter, and Tampa Electric Co. analyzed what would happen if its fuel supply systems were exposed to significant delivery delays.

Power system planning

As power systems grow and become more complex, new analytic tools will help planners ensure that these systems will continue to perform economically and reliably. New codes will also provide the analyses needed to make utilities plan for decisions about size, timing, and location of new generation and transmission facilities and about purchases of power from neighboring utilities, regional pools, and nonutility generators. This task involves distilling a wide variety of options into a few that are economically, environmentally, and socially acceptable, while assessing the risk and uncertainty associated with each.

One of the problems that must be addressed by system planners involves the transfer, or wheeling, of power from one utility to another. TRADE is a relatively new code that provides a standardized, step-by-step procedure for comparing costs and benefits of power interchange. The code uses a regression technique to interpolate among data from detailed simulation studies, such as those developed by EGEAS, and thus prepares a large series of possible interconnection options. Various attributes of each option, such as total operating costs, system reliability, and total capital requirements, can then be compared to determine an optimal set of trade-offs.

System reliability and stability are key considerations for planners examining system alternatives. The steady-state reliability of the combined generation and transmission systems of a single utility or power pool can be evaluated with SYREL. This code uses probabilistic methods to

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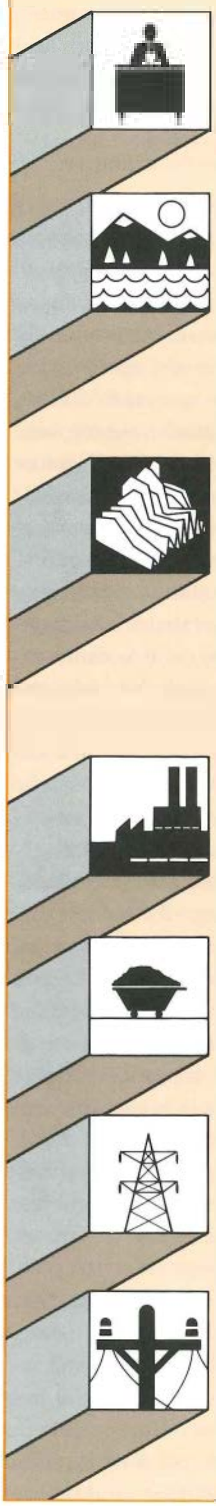


Corporate Planning	UPM	Utility planning model
	OVER/UNDER	Over/under capacity planning model
	TELPLAN	TELPLAN integrated system planning model
Environmental Planning	ADEPT	Acid deposition decision framework model
	TRIM	Transformer/capacitor risk management model
	COIL	Contaminated-oil economic risk management model
	ASK	PCB economic risk management model
	ILWAS	Integrated lake-watershed acidification study
	MYGRT	Migration of solutes in the subsurface environment
	EPAM	Sampling design for aquatic ecological monitoring
	EXPOCALC	Exposure assessment tool for electric fields
Demand-Side Management and Load Forecasting	REEPS	Residential end-use energy planning system
	COMMEND	Commercial end-use energy forecasting model
	HELM	Hourly electric load model
	LMSTM	Load management strategy testing model
	LOADSIM	Load shape simulation
	EMPS	EPRI methodology for preferred systems
	ESPRE	EPRI simplified program for residential energy
	DEUS	Dual energy use system
	COPE	Cogeneration options evaluation model
	COGEN3	Design model for cogeneration
Generation Planning	EGEAS	Electric generation expansion analysis system
	TCM	Technology choice model
	DETGEN	Decision tree generator model
	COMPETE	Competitive analysis of electric power generation
Resource Planning	CONTRACTMIX	Fuel contract mix model
	CMCM	Coal mine cost model
	RRCS	Rail routing and costing system
	CPCM	Coal preparation cost model
	UFIM	Utility fuel inventory model
Power System Planning	TRADE	Transfer capability objective
	SYREL	Transmission system reliability methods
	ETMSP	Transient/midterm stability/PFLOW
	STABIN	Transient stability program output analysis
Distribution Planning	UDPM	Distribution planning model
	DLFTM	Distribution load forecasting model
	PRAM/HISRAM	Distribution system reliability and risk analysis model
	SCALE	Simplified calculation of loss equations for distribution systems

determine the likely frequency and duration of outages and the amount of load not served under different sets of contingencies. SYREL is suitable for use in testing and demonstrating alternative approaches for improving system reliability and can thus be used to develop input options for TRADE.

Given the two or three most promising alternatives, a planner's next task is to analyze possible power disturbances and determine how well each system configuration will perform dynamically. ETMSP accomplishes this by using an interactive procedure to extend the conventional (from 0 to 10 seconds) transient stability analysis into the midterm range—about two minutes after a disturbance begins. This additional time is needed to ensure that the system will ride through the transient conditions after the initial shock. ETMSP can model large and complex systems. The code models power plants and automatic generation control while computing the shaft speeds of individual generators and intermachine oscillations as well as possible protective relay operation.

Although extremely accurate for the specific condition modeled, ETMSP analysis is costly and time-consuming. A way was needed to screen or bracket system conditions that would cause instability. This is provided by a new technique, STABIN, which uses a simple calculation to obtain results that would have required from three to five costly ETMSP runs.

Distribution

Distribution system planners have long needed better analytic tools for modeling system additions in ways that can be used to choose among available alternatives and for forecasting load growth in small areas because growth rates can vary widely from one locality to another nearby. UDPM provides the information needed to identify timing and location for addition of major cost items and to evaluate the effect of losses from various plans over a long period. The code contains five submodels, which cover substation location, substation sizing, load transfer, feeders, and system optimization. DLFTM produces load forecasts over short- or long-term periods for areas that typically cover quarter sections of 160 acres.

Improved tools have also been required for monitoring distribution system performance after the fact and for using this information to predict the future reliability of a system. PRAM/HISRAM provides these capabilities in an integrated package. The HISRAM module of this code provides a flexible structure for storage, retrieval, and analysis of distribution system outage data, and the PRAM model calculates a reliability index for each bus in a radial distribution system.

A simplified model of losses for each part of a distribution system can be provided by SCALE. The evaluation method on which this code is based was used to develop data and conduct comparison tests for the Salt River Project and Public Service Electric and Gas Co., New Jersey. Among other results, these projects found that more than 50% of all distribution system energy losses occur in distribution transformers.

The cornerstone of future utility planning

This concise overview of EPRI planning tools does not cover a number of codes that are in the development phase. These include codes that address issues of risk management, adoption of new technologies, and business planning aspects of utility companies.

Even though the problems facing utilities are becoming more and more complex, the software available to decision makers should be made more easy to use. Trade-offs must often be made between the quantity of input data required and the obtainable level of accuracy and speed. New computing technologies must be exploited. Personal computers, for example, are finding increasing use in utility applications, and EPRI now offers more than two dozen of its codes in versions that can be run on a personal computer.

Utility testing of each of EPRI's programs is needed to ensure that its applicability is well-established before the program is approved for general release. Successful development of new and even more powerful codes for utility applications depends on a close working relationship between EPRI and its member utilities. Testing of a code by various host utilities during its development phase provides a better understanding of its characteristics and accuracy and helps to develop improvements.

Individual EPRI divisions have also conducted surveys to determine how codes are being used by utilities. This information has been valuable in determining utility software needs. More such surveys will be conducted in the future.

EPRI is beginning to investigate improved graphic applications and expert systems as a means of helping decision makers at several levels of utility operations. Clearly, close cooperation with many individual utilities will be needed to provide the insights that will serve as the cornerstone for future innovations in software development. ■

Further reading

"UPM: Modeling at the Corporate Level." *EPRI Journal*, July/August 1985, pp. 31–32.

"Testing Load Management Strategies." *EPRI Journal*, May 1985, pp. 15–17.

"REEPS: Simulating Residential Response." *EPRI Journal*, July/August 1984, pp. 28–31.

"Fuel Supply Management: Charting a Course Through Uncertainty." *EPRI Journal*, December 1983, pp. 6–13.

"A Roadmap for Complex Decisions." *EPRI Journal*, September 1983, pp. 6–15.

"Generation Expansion: Streamlining the Analysis." *EPRI Journal*, June 1983, pp. 16–20.

"Forecasting the Patterns of Demand." *EPRI Journal*, December 1982, pp. 7–13.

"Ensuring Power System Stability." *EPRI Journal*, November 1982, pp. 6–13.

This article was written by Walter Esselman, director of Engineering Assessment and Analysis. Additional information was provided by Pradeep Gupta, Energy Analysis and Environment Division; Robert Iveson, Electrical Systems Division; and Clark Gellings, Energy Management and Utilization Division.

Surveyor Robot Is Ready for Utilities

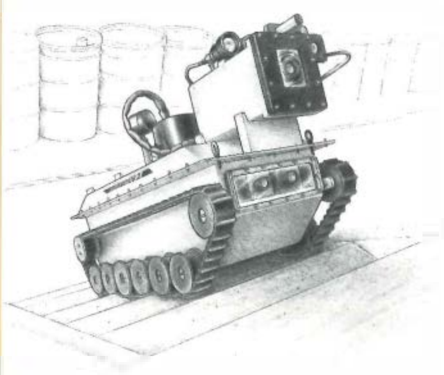
Robotics is expected to assume an increasing role in power plants, where the environment and the strenuous nature of many tasks pose limitations for plant personnel. At the forefront of advances in robotics is Surveyor, a general-purpose mobile vehicle developed by Automation Technology Corp. (ATC) as part of an EPRI research and development project.

Surveyor is extremely rugged and maneuverable—able to climb steps and to carry optical, audio, radiological, and a host of environmental sensors into controlled radiation areas. This untethered, remotely controlled surveillance system has now been commercialized and readied for field work.

Before it could qualify for the field, Surveyor was tested at Duke Power Co.'s Catawba Nuclear Power Station, at Public Service Electric and Gas (PSE&G) Co.'s Salem and Hope Creek generating stations, and at the robotics laboratory of the New Jersey Institute of Technology (Newark). These tests provided additional information and valuable recommendations for Surveyor modifications.

EPRI's Maintenance Equipment Application Center (MEAC) team, located at EPRI's Nondestructive Evaluation Center in Charlotte, North Carolina, was in charge of the test at Duke Power, where Surveyor was the first such device tested at the utility. Duke Power found that operating Surveyor at the Catawba plant gave its staff the opportunity to see the benefits and limitations of Surveyor firsthand. Having operated Surveyor and having viewed a demonstration by the MEAC staff, Duke Power personnel are now better able to evaluate this technology for potential application in hazardous environments.

As with any new technology, the user must learn to operate the equipment and to cope with the effects of the technology



on the plant and its operating personnel. Continued use of this equipment is providing the answers to several open questions—user acceptance, plant and personnel safety, and equipment reliability. Experience has shown that user acceptance, as it applies to plant personnel, should not be a problem because wherever Surveyor has been introduced, utility personnel have easily learned to operate this equipment.

Niagara Mohawk Power Corp. will be the first utility to employ Surveyor since the project testing was completed. After an engineering evaluation of the available technology, Surveyor was selected as the best vehicle to adapt to specific applications at the utility's Nine Mile Point station. Niagara Mohawk will use a newer, advanced vehicle that was purchased from ATC by KLM Technologies and modified by ATC to suit the utility. This vehicle is more rugged and has improved decontamination features, better ergonomics, and more-effective computer and control systems for the sensory systems and motor drives. Although Surveyor was originally configured for surveillance missions, the additional capability to install maintenance work packages will expand its role and value to the utilities. After field-testing the modified Surveyor at Detroit Edison Co.'s Fermi 1 facility, Niagara Mohawk intends to use this vehicle during 1986 for visual in-service inspection in high-radiation areas and for a major decontamination project at the Nine Mile Point plant.

Two principal questions remain to be answered: robotic safety and reliability. Because at this point robots still need human help to complete some tasks, what hazards do these vehicles present to plant personnel working in the same area? Could the plant be adversely affected by these vehicles during the course of normal operation? How reliable is the equipment? These questions will be answered as the technology is applied on a continuing basis.

A new organization, composed of utility engineers, manufacturers, and researchers, has been formed to expedite this learning process by encouraging cooperation between manufacturers and utilities, promoting the use of robotics in hazardous areas of power plants, and disseminating information on available equipment. Cochaired by Michael Pavelek of Bechtel National, Inc.–GPU (Three Mile Island) and Harry Roman of PSE&G, the Utility/Manufacturers Robot Users Group brings together the people who need the technology with the people who produce it.

Opinions differ on the pace of progress in this new technology. Some researchers see exciting new developments at hand, while others believe that there is a long road ahead before robots will be able to perform tasks that humans do routinely and easily, such as selecting the right size bolt, choosing the appropriate screwdriver or wrench, and knowing how much torque to apply.

Researchers continue to explore the enormous potential of robotics. With similar activities being performed underwater and in space, NASA technology is being analyzed to determine useful spinoffs. Meanwhile, Surveyor has improved our ability to function in hazardous environments. *EPRI Contact:* Floyd Gelhaus (415) 855-2024. *EPRI Licensee:* Automation Technology Corp., Columbia, Maryland.

Contacts

Harry Roman, Public Service Electric and Gas Co.; Judith G. Weinbaum, Duke Power Co.; Timothy Irving, Niagara Mohawk Power Corp.; George Kniazewycz, KLM Technologies, Walnut Creek, California; Chester A. Kus, Syndeco, Inc., Detroit, Michigan. ■

DSM Handbook for Rural Electric Systems

Today some rural electric systems (RESs) face the need for new capacity additions, while others seek to reduce reserve margins that have resulted from decreasing sales. In the past RESs have used conservation and certain kinds of load management but have had no integrated approach to deal with balancing energy supply and demand. The sharp rise in the cost of building and operating new generating plants and the changing economic conditions in rural areas compel these utilities to explore new ways to cope with their problems. As a result, RESs are turning more and more to the concept of demand-side management (DSM), which allows them to cut capital and operating costs by influencing consumer use of electricity in a way that produces desirable changes in load shape. *Demand-Side Management for Rural Electric Systems* (EM-4385), published by EPRI in collaboration with the National Rural Electric Cooperative Association, provides an overview of DSM issues, a framework for an RES to use in reviewing the potential for DSM, and suggestions for its implementation.

Focusing on rural cooperatives and on rural generation and transmission utilities and their customers, the handbook discusses the practical aspects of DSM: its place within the utility planning process, demand-side strategy, selection of appropriate options, and program implementation and monitoring. The sections on farm end uses and program implementation and monitoring have been expressly written for RESs, and the matrices of options and end uses have been tailored to energy use on the farm. Buckeye Power, Inc., Oglethorpe Power Corp., Sheyenne Valley Electric Coop., Inc., and Minnkota Power Cooperative, Inc.—the subjects of four case studies included in the handbook—are representative of the various types of rural electric systems, and the descriptions of their use of DSM bring these concepts to life. The case studies provide insights that will help the reader appreciate the benefits of DSM, as well as the multitude of options, the implementation issues that arise, and the importance of monitoring the program over a period of years. *EPRI Contacts:* Ahmad Faruqui (415) 855-2630; Clark Gellings (415) 855-2610; Orin Zimmerman (415) 855-2551 ■

Commercial and Industrial Lighting Handbook Here

Planning and management of energy use is an essential utility service that benefits both the utility and the customer. Because lighting accounts for 20–25% of total electricity consumption, the utility industry has a vested interest in helping its industrial and commercial customers select the most appropriate and energy-efficient lighting systems for their needs. The new EPRI *Lighting Handbook for Utilities* (EM-4423) emphasizes the importance of lighting, its end uses, its components, and the opportunities to reduce demand.

Lighting systems today should be efficient and designed to suit the tasks to be performed at a certain location. The handbook includes sections covering indoor and outdoor lighting options for both new and existing buildings. Designed to be a comprehensive study of lighting options for the commercial and industrial sector, this manual touches on diverse aspects of lighting, such as controls, lighting-related energy use and demand, efficiency, sources and selection factors, and maintenance. Important nontechnical issues are treated in its sections on cost-effectiveness decisions, acquiring and accepting lighting systems, and information sources. Knowledge in these areas can help the utility representative influence customer use of electricity to produce desirable changes in the utility load shape.

This book should appeal to people with a broad range of experience in the lighting field: the glossary is a valuable resource for the novice, while the list of additional sources of lighting information is a valuable reference for everyone in the field. Although not a design guide or the only source of information, this handbook can be used to help customers make wise decisions that are consistent with the utility's demand-side objectives. *EPRI Contact:* Gary Purcell (415) 855-2168 ■

R&D Status Report
ADVANCED POWER SYSTEMS DIVISION

Dwain Spencer, Vice President

COAL GASIFICATION TESTS AT TVA

*Coal gasification is an important future option for electric power generation. Entrained flow-slagging processes, such as Texaco Inc.'s, are prominent choices for gasification–combined-cycle (GCC) plants. Since 1980 the Tennessee Valley Authority (TVA) has operated a 200-t/d, oxygen-blown Texaco quench gasifier with associated gas cleanup equipment as part of its ammonia-from-coal project. In 1983 successful tests were completed at this facility with Exxon Donor Solvent coal-liquefaction residue as feedstock (*EPRI Journal*, November 1984, pp. 46–48). The Texaco process was successfully demonstrated as part of Southern California Edison Co.'s 1000-t/d, combined-cycle Cool Water power plant near Barstow, California (*EPRI Journal*, December 1984, pp. 16–25). During 1984 and 1985 TVA completed test runs, which included three EPRI-selected coals, for the purpose of obtaining data relevant to a number of EPRI projects, including the planning of coal tests at Cool Water (RP1459).*

Gasification test program

Four coals were tested, including Cool Water's design coal from Utah, candidate coals from the Illinois No. 6 and Pittsburgh No. 8 seams, and a high-ash-fusion Maryland coal (not reported herein). Each coal was gasified for 8–20 days with on-stream factors ranging from 79 to 100%. A number of variables were studied, with major emphasis on varying the oxygen-to-carbon ratio. Gasifier data were obtained over a range of conditions (Table 1).

Texaco researchers determined the type and quantity of additive for achieving a high slurry concentration during operations with the Illinois coal, and Texaco Development Corp. and TVA collaborated on the design and installation of a slurry preheater for operations with the Pittsburgh coal.

One minor but recurrent problem was the loss of some of the gasifier thermocouples, the most significant of which occurred during the test of the Illinois coal. Fortunately, the failures occurred singly, thus allowing TVA to develop reliable correlations between the gasifier temperature of Illinois coal and the unreacted methane content of the scrubbed gas. (Thermal cracking reactions of volatile matter in coal produce methane, other by-products, and soot carbon. As the temperature is increased, these intermediates react further to produce syngas.) Following the loss of reliable thermocouples, the set point was maintained by on-line methane and CO_2 analyzers, and the test was completed without a shutdown. There was disagreement in thermocouple readings during the Pittsburgh coal test, and uncertainties exist about the comparable range tested.

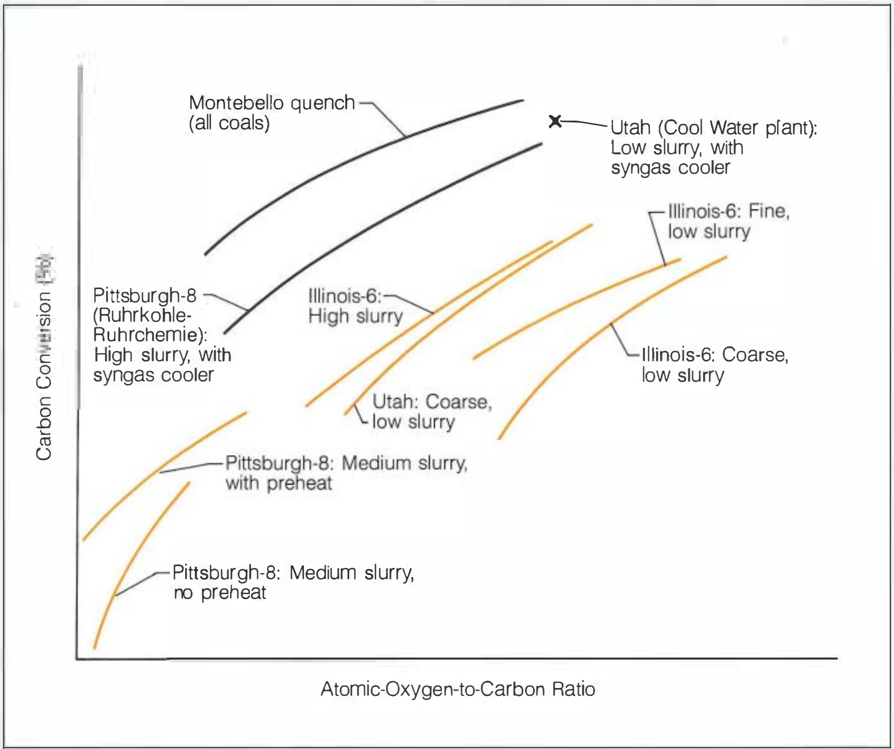
Wastewater characterizations were performed during each coal test. Comparing these data with information from other gasifiers is helping researchers understand the reactions that form by-products and their effect on the water chemistry (RP1654). A slipstream test pipe loop was developed to study methods to minimize scale-forming tendencies. Wastewater samples were taken from each coal test for separate treatability studies (RP2526); and in another environmental investigation, TVA and Radian Corp. are jointly conducting slag leachability studies (RP2659). Advanced gasifier refractory materials were also tested (RP2048) during the program.

In determining gasifier performance, the ratio of atomic oxygen to carbon (O/C) is an important independent variable. The O/C operating range is determined by the gasifier temperature; in general, the upper limit is based on refractory wear, the lower on slag (molten ash) viscosity. Depending on the carbon conversion range of the particular feedstock, the lower limit is not always approached. To obtain a characteristic feedstock performance curve, carbon conversion is plotted as a function of the O/C. Researchers developed these curves for the various coals tested at TVA (Figure 1). Usually, increases in the oxygen feed (gasifier temperature) produce proportionately greater conversion up to a point, beyond which the curve flattens and

Table 1
OPERATING CONDITIONS FOR TVA GASIFICATION TESTS

	Coal		
Operating Conditions	Utah	Illinois No. 6	Pittsburgh No. 8
Coal oxygen/ash content (wt%)	14.9/8.4	8.2/13.3	7.4/6.9
Coal heating value (Btu/lb)	11,930	12,450	14,100
Coal slurry concentration (wt%)	57–62	61–67	55–64
Gasifier pressure (psig)	500	500	500
Gasifier temperature (°F)	2350–2650	2400–2650	–
Feedstock rate (t/d)	149–187	182–191	141–164
Oxygen rate (10^3 ft^3/h)	135–180	168–185	148–164
Carbon conversion (%)	93–97	93–97	86–92
Syngas CO_2 (%)	20–24	16–20	13–18
Load (10^6 ft^3/d H_2 and CO)	7.5–9.6	9.3–10.3	9.0–10.6
Specific load (ft^3/lb coal)	25–26	25–27	30–32
Specific oxygen consumption (ft^3/10^3 ft^3 H_2 and CO)	427–475	393–459	352–391

Figure 1 Feedstock performance curves (color) for Utah, Pittsburgh, and Illinois coals used in the TVA quench gasifier. Data for Montebello, Cool Water, and Ruhrkohle-Ruhrchemie are in black. Performance—the percentage of the coal carbon that is converted—is shown as a function of the O/C. The conversion range depends on grind size and gasifier, whereas the O/C operating range is a function of slurry concentration and coal heating value.



increased oxygen input produces unwanted CO_2.

The relative O/C range required to convert the coal is an indicator of the process efficiency. There are two principal sources of inefficiency: (1) portions of the feed and product must be burned to release enough heat to maintain the required temperature, and (2) only part of this combustion product (CO_2) can be used, in turn, to produce additional syngas from unconverted feed. Combustion can be reduced by minimizing the amount of heat required to vaporize the liquid or by increasing the energy content of the feed. This can be accomplished by increasing the slurry concentration, by increasing the feed heating value (carbon content), and by preheating the feed. Each of these techniques can lower the oxygen required to achieve a given temperature and conversion.

At the normal slurry concentration, the O/C value required to achieve a conversion level appears lowest for the Utah coal, which had a high oxygen content, compared with the others. However, the reduction in the oxygen requirement by means of the high slurry concentration achieved with the Illinois coal offset the increased reactivity of the Utah coal (discerned at low slurry concentration).

The greater energy content (heating value) of the Pittsburgh coal relative to the others tested decreased the O/C required to achieve the allowable temperature range.

Preheating the feed was studied during the run with the Pittsburgh coal. Although a relatively moderate increase in slurry temperature was achieved by using the low-pressure steam available, the O/C was slightly lower at a given conversion than it was with the unheated slurry.

The relative ease of grinding the Illinois coal permitted the use of an alternative mill plate, thereby allowing a modest range of slurry grind sizes to be evaluated. The finer grind resulted in a small increase in the conversion range.

A higher conversion was indicated for the Utah coal in the Cool Water plant with its radiant-cooled gasifier (water-tube wall) than with the direct water-quench design used at TVA. Data from the Ruhrkohle-Ruhrchemie radiant-cooled gasifier also showed a higher conversion range for the Pittsburgh coal than was reported for the TVA unit. Data from Texaco's smaller-scale Montebello direct-quench gasifier show a conversion range similar to those reported for the large-scale radiant-type gasifiers. The reason for the apparent performance difference for the large-scale quench gasifier is not known.

Researchers are continuing to study this information, and additional data reconciliation may be required before conclusions can be made. To be considered are differences in grinding systems, burners, and gas cooldown profiles (time-temperature histories).

Coal reactivity depends on the pore surface area of the ground coal (*EPRI Journal*, December 1983, p. 44). The surface reaction sites (and rate) can be increased by finer grinding, as was indicated in the Illinois coal test. The mill used at Cool Water (and at Ruhrkohle-Ruhrchemie) can achieve an even finer grind, which could account for a portion of the conversion improvement.

With earlier burner scale-up designs, load-range effects were indicated (*EPRI Journal*, May 1983, p. 36). An advanced burner design was used for the results reported herein from the various facilities. The TVA burner did not indicate a performance (mixing) effect at 75% load turndown with Utah coal. However, it is considered possible that such limitations could have affected TVA results under certain conditions used with the other coals tested.

Regarding the possibility of effects from the configuration of the gasifier, the water-tube (radiant) design allows a slower cooling of gasifier effluent and therefore more time for additional conversion to take place through reactions with CO_2 and steam. Kinetic effects could be significant with the faster cooldown profile used in the large-scale quench gasifier design. But there is some variability in the measured TVA temperatures compared with those calculated by heat balance; as a result, a kinetic temperature effect could not be positively confirmed.

The amount of oxygen and the extent of combustion (CO_2) required to convert a given coal are important factors in evaluating a feedstock. The specific oxygen consumption and specific load are used as their indicators. These in turn are a function of the O/C, the slurry concentration achieved, and the coal composition. Specific oxygen consumption is defined as the amount of oxygen required to produce a given quantity of syngas; the specific load is the amount of syngas produced for a given quantity of coal. Researchers determined these key parameters for each coal tested.

The high slurry concentration achieved with the Illinois coal reduced the quantity of CO_2 in the syngas and increased the production (load), compared with the Utah coal. Thus, the range of specific oxygen consumption was reduced. However, the high ash content, compared with the others, offset a portion of this advantage. The high heat content of the Pittsburgh coal resulted in a lower oxygen requirement, which reduced the quantity of CO_2 in the syngas below that achieved with the Illinois coal. The high carbon (low oxygen plus ash) content of the Pittsburgh coal (compared with the others) reduced the amount of coal needed to produce a given amount of syngas. Thus, a higher specific load was achieved. Because it is expected that the conversion will be higher in the Cool Water radiant-cooled gasifier, this load benefit should become more pronounced.

To summarize, Pittsburgh and Illinois coals tested at TVA appear to be excellent candidates for demonstration at Cool Water. Unit power production is expected to increase when these higher Btu and slurry concentration coals are used.

Texaco Development cautions that the TVA plant is a demonstration unit and is not representative of present commercial designs of the Texaco coal gasification process. As a result, neither the process and equipment problems nor the gasifier performance observed in the TVA tests is necessarily typical of current commercial plants using the Texaco coal gasification process.

Once-through methanol program

Coproduction of electricity and methanol is an effective way to maximize the output of a GCC power plant (*EPRI Journal,* June 1983, p. 21). In this approach, most of the hydrogen in the CO-rich gas is converted to methanol in a single step, thus avoiding costly CO shift, CO_2 removal, and gas recycle and leaving the remaining gas to be burned as turbine fuel. As a result of these savings, once-through methanol (OTM) is projected to produce the lowest-cost coal-derived liquids at only a small increase in cost above that of medium-Btu fuel gas. OTM appears particularly valuable when significant load following is needed in a baseload plant. The cost of adding methanol synthesis for energy storage is less than the avoided cost of equivalent gasification capacity to handle daily load peaks. Adding OTM capability can also provide low-NO_x fuel for additional combustion turbines, as well as ensure fuel availability. This coal-based peaking/intermediate power would be dispatched before premium fuel–based power. Further, OTM has the potential to reduce power costs through product diversification.

EPRI has been participating in the development of a liquid-phase methanol process that can convert a portion of the CO-rich gasifier product in a GCC plant. The technical feasibility of this process has been proved in a pilot-scale operation using simulated product gas (RP317). Chem Systems, Inc., has prepared a scale-up plan (RP2532-1). TVA is conducting a process-screening and cost estimate study (RP2532-2) and proposes to begin preliminary engineering for an OTM demonstration using coal-derived gas at its coal gasification facility.

Only hydrogen, carbon oxides, and water, with smaller amounts of nitrogen, argon, hydrogen sulfides, and methane, are known to be present in appreciable amounts in the gasifier product. A few impurities, such as hydrocarbon gases, ammonia, and some sulfur compounds (other than the hydrogen sulfides), have been reported in minute quantities (ppm). Certain volatile metals may also be present at low levels. Beyond this, little is known about other trace constituents that may be present in the gas at various stages of treatment or to what extent they would (if present) affect the methanol catalyst.

TVA researchers studied the performance of the gas treatment systems during the gasifier coal tests. Initially, the CO-shift converters (for the ammonia-from-coal process) were used, and a loss in activity was observed. However, these were later bypassed in order to operate as in a GCC plant.

The carbonyl sulfide (COS) converter (used before Selexol treatment to help achieve higher sulfur removal for chemical synthesis) reduced COS levels to 10 ppm in both shifted and unshifted gas, indicating the reaction to be chemical-equilibrium-controlled at the normal operating temperature. However, kinetic effects were evident during upsets when lower temperatures were experienced, indicating the need for improved control. Activity maintenance in the converters required some moisture reduction and reheating of the gas to protect the catalyst. No activity loss was detected, but operation with unshifted gas was relatively brief.

TVA's Selexol acid-gas removal system includes additional solvent processing and recycling beyond that used at Cool Water to achieve the higher sulfur-removal efficiencies required for chemical synthesis (e.g., ammonia, methanol). During the run with Utah coal, this system achieved design sulfur levels of 1 ppm in the treated shifted gas. After system modification to resolve problems encountered with the high-sulfur Illinois coal, design performance was also achieved when unshifted gas was treated during the run with the Pittsburgh coal. Further modifications will be required to minimize removal of CO_2, which is useful in improving methanol production and power generation. Such modifications must also address COS selectivity so as not to adversely affect downstream treatment requirements.

The sulfur guard beds achieved synthesis gas specifications during the run with the Utah coal. However, with the CO-rich gas it was necessary to operate with the zinc oxide bed at a lower temperature (because heat was not available from the exothermal shift reaction), which was less effective for sulfur (particularly COS) removal. To avoid reheating the gas, alternative guard systems that operate near the methanol synthesis temperature are being studied.

TVA researchers analyzed the gas from each treatment stage. Small tubes containing methanol catalyst were also exposed to the gases, analyzed, and checked for activity. Low levels of metal carbonyls and other constituents were identified in the raw gas. Most of the more polar species (cyanides, chlorides) were effectively removed by the Selexol treatment. However, TVA data and experience at the LaPorte liquid-phase methanol pilot plant (*EPRI Journal,* November 1985, p. 48) indicate that metallurgical upgrading will be necessary to minimize carbonyl compounds. Additional gas treatment may also be required.

To summarize, acid-gas removal modifications and the use of specially designed guard beds, together with metallurgical changes, appear to offer adequate protection for the OTM catalyst. *Project Manager: W. H. Weber*

GAS TURBINES FOR THE FUTURE

Gas turbines are used alone in simple-cycle gas turbine power plants, which supply power for peak loads, and also as the basic generating component in combined-cycle baseload plants, where their output is augmented by that of steam turbines to increase overall plant efficiency. Unlike many aspects of the utility-scale power generation industry, gas turbine technology has been moving ahead fairly fast, one reason being that it shares in the benefits of the highly funded federal R&D program for aviation gas turbines. In general, turbine progress is characterized by large, incremental advances in performance. At intervals of about 15 years, new-generation turbines are introduced, refined, and eventually installed in relatively large numbers. At the time of their introduction, the new-design gas turbines may be operated below design output, pending further developments and improvements of components. As more on-line experience accumulates, still other improvements may be made. But major performance advances await the next design generation. A new generation of turbines is being readied for the market now, and R&D is already under way on equipment that will not make its appearance at the utilities until the turn of the century.

Next-generation gas turbine engines (about to be introduced) will have power ratings into the

120–150-MW range (simple cycle), significantly higher than the 70–100-MW units now in service. When the new turbines are installed in combined-cycle plants, where the energy in the high-temperature gas turbine exhaust is used to generate steam for a steam turbine, the efficiency levels are expected to rise from the present value of about 42% higher heating value (HHV) to about 46% HHV. And for the generation to follow (in about the year 2000), work is proceeding to determine the performance potential and development requirements for prospective new-type gas turbine power plants (RP2620-1).

New generation

Thus far, RP2620-1 has concentrated on improved standard gas turbine engine designs with single-shaft, in-line compressors, combustors, and turbines. The emphasis has been on achieving better power plant performance by improving system materials and by using alternative fluids to cool the turbines. The alternative cooling fluids (in addition to standard compressor bleed air) are precooled cooling air, open-circuit steam, and closed-circuit steam.

Precooled cooling air is obtained by taking air from the compressor exit (typically at about 700°F, 370°C), cooling it to about 150°F (65°C) in a heat exchanger, and then using it to cool turbine components. But it was found that precooling increased specific power output by only about 0.7%. Also, the energy removed in the heat exchanger must be otherwise used or the efficiency suffers. For example, it may be most effectively used thermodynamically to heat the fuel. This produces a slight increase in efficiency (about 0.4%).

When open-circuit steam is used to cool the turbines, cooling air is replaced (in most of the turbine stages) by low-pressure, low-temperature steam generated in the heat-recovery steam generator. The steam flow is similar to that of cooling air: through the blading of one stage in order to cool it and then out, mixing with the main combustion product gas to help provide power to the following stages. The steam has three principal advantages over cooling air taken from the compressor exit: it requires only negligible pumping energy, it has a higher heat-transfer coefficient, and it is at a lower temperature. Unfortunately, using open-circuit steam to cool the turbines results in a significant (2.4%) reduction in the efficiency of the combined-cycle system because the steam bled off for cooling the blades is not available for powering the steam turbine, which would be the most energy-effective use of the steam. Open-circuit steam cooling does, however, allow an increase in plant-specific power of about 8%.

Closed-circuit steam cooling eliminates the principal disadvantage of open-circuit steam cooling, which is the lost energy that could otherwise help drive the steam generator. In the closed-circuit system, high-pressure steam is bled off the high-pressure loop of the exhaust heat-recovery steam generator. It is piped in a closed circuit to the turbine blades, where it absorbs heat, and then on to the steam turbine. The internal cooling passages in the turbine blades do have to be redesigned in order to contain the steam in the blading.

The closed-circuit scheme retains the main advantages of steam cooling—little pumping energy required, high heat-transfer coefficient, and relatively low temperature. In addition, it makes full use of the cooling steam in the steam turbine, and the heat absorbed from the turbine blades acts as another superheat stage. Combined-cycle efficiency is about 3% better with closed-circuit steam cooling than it is with ordinary cooling air, and the closed-circuit technique also increases plant-specific power by about 8%.

The development of closed-circuit cooling, however, is not as far advanced as that of other techniques. Designs for getting the steam on and off the engine, for distributing it equally to all blading, for recovering it from the blading, and for maintaining the integrity of the rotating blades containing high-pressure steam, have yet to be fully worked out and tested. Thus, closed-circuit steam cooling is a promising approach to better cooling of gas turbine blades, but further development is required, and a successful outcome is not a certainty.

The combined-cycle efficiencies range from 42% HHV for the machines in service now to 46% for the next-generation machines (available soon) to a projected 48% for future-generation machines (available about the year 2000) with advanced air cooling and up to 51% for those with closed-circuit steam cooling. (The use of open-circuit steam cooling is not forecast, as it would drop the efficiency back to about 45%.)

Power levels projected for the future-generation turbines are up dramatically over those of the present in-service machines. Single gas turbine simple-cycle plants of 170–200 MW or higher are expected. Power levels could even be increased further—up to 300 MW—by increasing the flow capacity of the compressors. And in a combined cycle the power output would be at least 30% higher. Thus the gas turbine plant of the future will probably be a large output facility with a high-efficiency combined-cycle system. In planning for future expansion, the utilities should consider these new and projected developments in gas turbine technology.

Future generation

As EPRI's study of gas turbine development continues, attention will center on unconventional gas turbine cycles: the intercooled-steam-injected cycle, the reheat-intercooled cycle, and the evaporative-regenerative cycle.

In the intercooled-steam-injected cycle, the turbine exhaust is used to generate steam, which is then routed back through the gas turbine engine to increase the engine's power. The compressor in this system is also intercooled, which makes possible a high pressure ratio, reduces the work absorbed by the compressor, and reduces the temperature of the cooling air.

In the reheat-intercooled cycle, combustion products are refired following their partial expansion in the turbine. This cycle produces higher specific power and efficiency than do standard designs, but at the expense of more turbomachinery components. System performance is optimized at a very high pressure ratio so that intercooling is again advantageous.

The evaporative-regenerative cycle provides for increasing the mass and heating the flow to the combustor. Hot water is sprayed into the flow on the outlet side of the compressor; the augmented flow then passes through a recuperator, which heats the flow before it enters the combustor. The hot turbine exhaust is the heat source for the recuperator and for the hot water.

Studies of these three gas turbine cycles will make it possible to determine how useful they may be to the utilities as future options in electric power generation. *Project Manager: Arthur Cohn*

R&D Status Report
COAL COMBUSTION SYSTEMS DIVISION

Kurt Yeager, Vice President

LOW-NO_x CELL BURNER

The simplest and lowest-cost method for controlling emissions of nitrogen oxides (NO_x) from utility boilers is to use low-NO_x burners. These burners, which inhibit NO_x formation during combustion by delaying the mixing of fuel and air in the flame zone, have been incorporated into the design of new boilers and are the basis for meeting New Source Performance Standards. Although retrofittable low-NO_x burners have been developed for a large segment of the coal-fired boiler population, existing designs are not compatible with wall-fired boilers equipped with cell burners. In a joint effort, Babcock & Wilcox Co. (B&W) and EPRI have developed a retrofittable low-NO_x cell burner capable of a 50–60% reduction in NO_x emissions. This new burner is now ready for commercial application.

Cell-burner-equipped utility boilers were manufactured by B&W in the 1960s, when economic factors dominated boiler design criteria. The design objective was to minimize the size of the furnace, and hence the capital costs, by minimizing the size of the heat release zone. Today 38 cell burner units are in operation in the United States, primarily in the eastern and central regions. They range from 220 to 1300 MW; the average size is 700 MW. These boilers represent a total generating capacity of 26,000 MW.

The unique cell burner design combines two or three circular register burners in each module, or cell. The most common type is the two-burner (or two-nozzle) cell, which accounts for about 90% of the cell burner generating capacity (Figure 1a). The design's features result in high combustion intensity, as required for the smaller furnace volume, but also correspondingly high NO_x emissions, typically in the range of 1.0–1.8 lb/10^6 Btu.

Burner development

The prospect of increasing environmental pressure to reduce national NO_x emissions motivated the effort to develop combustion NO_x control technologies for cell-burner-equipped boilers. The existing low-NO_x burner designs were not applicable to this boiler class because of the close spacing between adjacent burner nozzles in the boilers. Without expensive modifications to furnace waterwall pressure parts, this arrangement cannot accommodate the burner modifications necessary for the lower-velocity, gradual mixing characteristic of conventional low-NO_x designs. Combustion staging, a potential alternative to low-NO_x burners, was not considered a viable option for cell burner units because of concern about increased slagging and corrosion, both of which had already occurred with some cell burner boilers in unstaged operation.

To screen candidate designs for a retrofittable low-NO_x two-nozzle cell burner, pilot combustion tests (6×10^6 Btu/h) were conducted at B&W's Alliance Research Center. The goal was to reduce NO_x emissions to approximately 50% of uncontrolled emissions without adverse effects on plant performance or operation. To minimize retrofit capital costs, a primary design criterion was that the new burner be retrofittable without modification of furnace waterwall pressure parts. Further, the new design was to alleviate the mechanical problems frequently experienced with the standard cell as a result of locally high temperatures that cause warped secondary air linkages.

The most promising design was selected for further development (Figure 1b). In this burner all the coal is diverted through one enlarged coal pipe in the lower nozzle, and the upper nozzle is used as an air port only. The enlarged coal pipe is sized to maintain the same firing rate as in the standard cell. The design features a number of controls to facilitate flame shaping and air distribution and promote flame stability. These new controls eliminate the problem-prone air registers and linkages of the standard cell. The low-NO_x design concept for two-nozzle cells can, in principle, be applied to three-nozzle cells as well, although this application is beyond the scope of the current development effort.

Pilot combustion tests

An extensive series of pilot combustion tests was conducted to characterize the performance of the low-NO_x cell burner over a range of operating conditions. Two pilot combustion facilities were employed: B&W's test furnace (also used for the burner design screening tests), which has a maximum total firing rate of 6×10^6 Btu/h, and EPA's large watertube simulator (LWS) furnace, which is operated by Energy and Environmental Research Corp. and has a maximum total firing rate of 100×10^6 Btu/h. Scale-up confidence was increased by following the smaller B&W pilot development tests with the larger-scale LWS pilot verification tests. This approach was helpful to B&W in calibrating in-house predictive models. In each of the pilot test series, a comparative evaluation of standard cells and low-NO_x cells was made. Two coals were used: Ohio No. 6, a high-volatile bituminous coal, and Lower Kittanning, a medium-volatile bituminous coal. These two are representative of coals burned at many cell-burner-equipped boilers.

In the initial test series at the B&W furnace, two cells were tested (one above the other) on a single firing wall. Each cell had a firing rate of 3×10^6 Btu/h. In the subsequent, larger-scale combustion tests at the LWS furnace, four cells were tested in a two-by-two array, again on a single firing wall. The firing rate of each cell was 25×10^6 Btu/h, or about one-tenth that of a typical full-scale cell.

Figure 2 presents emission results for the standard and low-NO_x cells. Standard cell operation in both pilot furnaces resulted in NO_x emissions in the range of 1.1–1.7 lb/10^6 Btu, a range typical of full-scale units. Although emissions with Lower Kittanning coal were very similar in the two furnaces, Ohio No. 6 coal yielded higher NO_x emissions in the B&W furnace. This difference is explained by the high volatility of Ohio No. 6 coal and the different thermal characteristics of the test furnaces.

For optimized low-NO_x cell operation, NO_x emissions in both furnaces were reduced to 0.4–0.7 lb/10^6 Btu, or about 50–60%, with good flame stability. Similar reductions were obtained over the burner's full turndown range.

Trade-offs in NO_x emissions and flame length were also evaluated. Greater NO_x reductions were generally accompanied by longer flames. For the optimized low-NO_x con-

Figure 1 Standard two-nozzle cell burner and low-NO_x cell burner. The standard cell's two closely spaced, circular register burners are designed for high-velocity, turbulent mixing, which results in rapid combustion. The low-NO_x design's primary feature is the integrated air staging port. It also has five adjustable control devices. Two sliding disks regulate air flow to the burner and the air nozzle (and thus control burner zone stoichiometry), and three adjustable devices control flame shape and stability—directional vanes in the air throat, spin vanes in the secondary air passage of the burner nozzle, and a movable coal impeller.

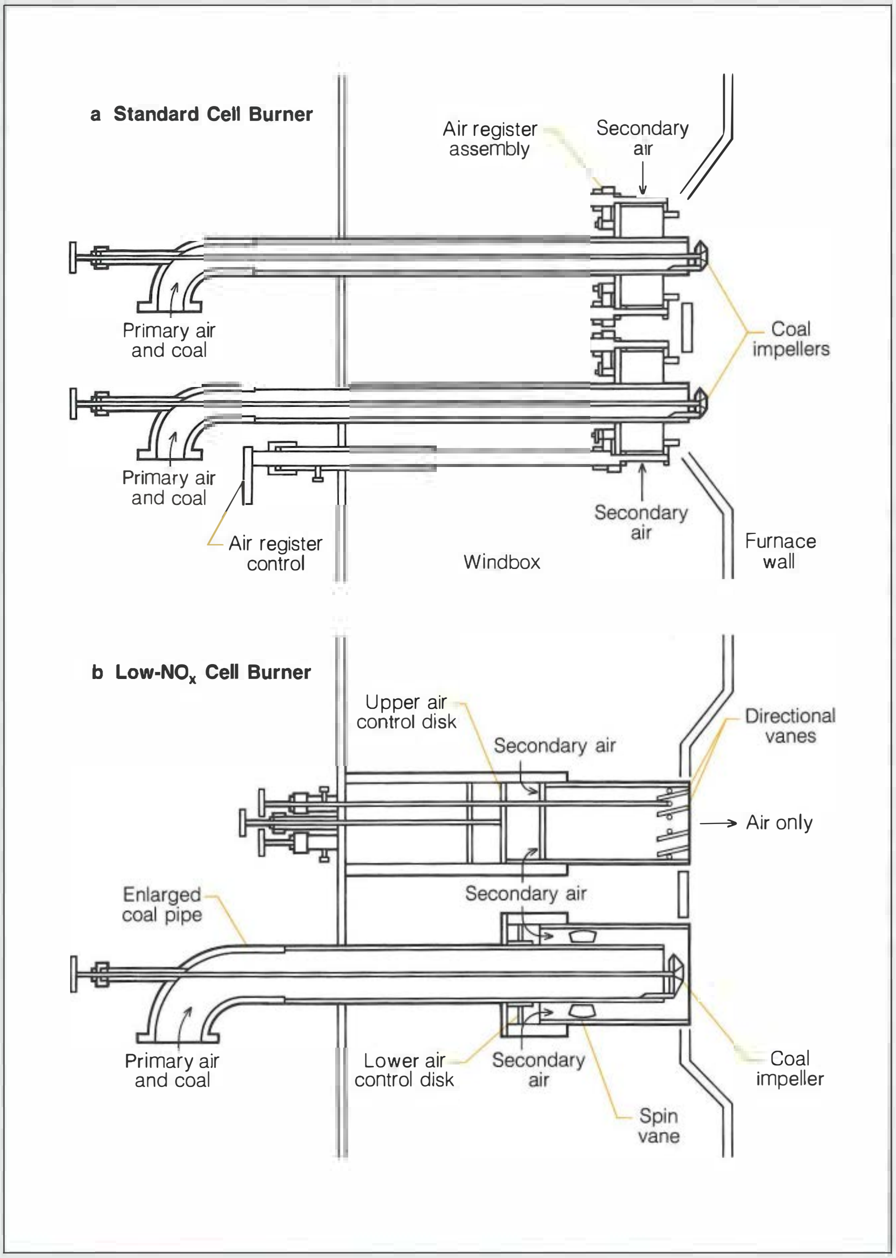
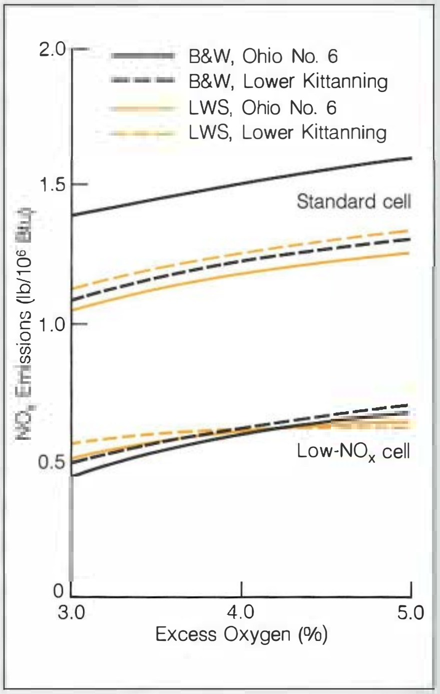


Figure 2 Pilot-scale NO_x emissions for the standard cell burner and the optimized low-NO_x cell burner over a range of typical excess oxygen levels. The tests were run at the B&W test furnace (6×10^6 Btu/h) and the LWS furnace (100×10^6 Btu/h) and used two coals, Ohio No. 6 and Lower Kittanning.



ditions shown in the figure, a 50% increase in flame length was observed in both pilot test series. Most cell-burner-equipped boilers are expected to accommodate such increases in flame length. The built-in operational flexibility of the low-NO_x cell will help ensure that acceptable flame characteristics can be achieved for the range of site-specific boiler design conditions.

Good combustion efficiency was achieved with the low-NO_x cell. Unburned-carbon emissions (as a percentage of the ash by weight) for both the low-NO_x and standard cells were below 1% in the B&W facility. Somewhat higher unburned-carbon emissions (below 4%) were observed in the LWS furnace. Judging from previous test experience in the LWS with other commercial burner designs, unburned-carbon levels well below 4% can be expected in full-scale applications of the low-NO_x cell. On the basis of slag deposit analyses, measurements of corrosive gas species, and visual observations, no significant increases in slagging and corrosion are expected with the new cell.

Full-size prototype cell

Encouraged by the results of the pilot-scale tests, B&W designed and fabricated a single full-size (250×10^6 Btu/h) prototype low-NO_x cell. It was installed at Dayton Power and Light Co.'s 600-MW Stuart Unit 3 for a one-year, full-scale evaluation to confirm the operating flexibility of the low-NO_x cell and its improved mechanical reliability over the standard cell design. (Because only one low-NO_x cell was installed, NO_x emission data are not available.)

One year of operation has been completed, and both mechanical reliability and burner operation have been good. Ultrasonic measurements of tube wall thickness adjacent to the low-NO_x cell were made during scheduled outages; they have revealed no significant increases in corrosion rates. Plans call for continuing to operate the prototype burner for another year.

On the basis of the pilot combustion test results, the full-scale single-cell evaluation at Dayton Power and Light, and B&W's scale-up predictions, EPRI and B&W are currently seeking utilities with cell-burner-equipped boilers to host a complete retrofit and demonstration test program. This effort will represent the last step in confirming the commercial viability of the new low-NO_x burner. It is anticipated that NO_x reductions equivalent to those in the pilot tests will be achieved (50–60%) and that unburned-carbon levels will be comparable to those of other commercial burner designs. No significant impact on boiler slagging or corrosion is expected. B&W estimates retrofit capital costs to be $2–$5/kW. *Project Manager: David Eskinazi*

ON-LINE COAL ANALYSIS

The on-line, continuous analysis of coal can deliver real-time coal quality information that can reduce the cost of many coal operations at power stations and coal-cleaning plants. This new analytic technology combines four measurement methods—prompt gamma neutron activation analysis (PGNAA), neutron transmission, microwave attenuation, and gamma transmission—that are nonintrusive, nondestructive, and capable of analyzing large coal throughputs (i.e., quantities measured in tons per hour rather than milligrams per day, as with current laboratory analyses). EPRI has sponsored a series of projects in this area, including the testing and engineering evaluation of an on-line coal sulfur analyzer at Detroit Edison Co.'s Monroe station and, under contract with Bechtel National, Inc., a study of selected applications for on-line coal analysis. The major effort (RP983) has entailed the development (starting with bench-scale equipment), fabrication, and demonstration of a full-scale, prototype on-line coal analyzer. Called CONAC (for continuous on-line analysis of coal), this instrument system determines coal elemental composition, ash concentration, heating value, and moisture content. This article highlights recent results from the CONAC demonstration, which has been cosponsored by the Tennessee Valley Authority (TVA) and hosted at its Paradise steam plant. Additional information on applications and operating installations for on-line coal analysis is available in an EPRI Video Memo.

Potential applications

EPRI's work in developing and demonstrating on-line, continuous coal analysis technology is motivated by the fact that the coal quality information currently used by utilities is not available for application in day-to-day plant operations and does not account for the variability of as-fired coal. (Typically, it takes days or weeks from the time coal is sampled to obtain the results of laboratory analyses.) If this information were available on-line, utilities could improve many coal operations that depend on coal quality, including the following.

▫ Coal blending. An analyzer can be employed to produce a more nearly homogeneous coal blend and to minimize the use of higher-quality, higher-cost coal in blends. The sulfur analyzer at Detroit Edison's Monroe station is being used in a coal-blending operation to meet sulfur dioxide emission requirements, and it is lowering the utility's coal costs while providing a more nearly uniform coal quality.

▫ Coal-cleaning plant control. An analyzer can monitor cleaned coal to ensure the production of a fuel that can meet emission requirements. TVA is evaluating a batch sulfur analyzer (based on EPRI-developed technology) for this purpose, and Pennsylvania Electric Co. is investigating a similar application for an on-line analyzer developed with its support and manufactured by MDH-Motherwell, Inc.

▫ Monitoring of as-received coal quality. With an on-line analyzer, utilities can continuously assess the quality of incoming coal shipments and reject shipments that do not conform to contract specifications. They can also use coal property information from the analyzer for the purpose of commercial pricing. Pennsylvania Electric and the Central Electricity Generating Board of the United Kingdom are evaluating analyzers for this use.

▫ Power plant performance control and monitoring. Potentially a major application of coal analyzers, this is also the application where a determination of the economics and benefits is most needed. A precise knowledge of as-fired coal properties could allow a utility to determine heat rate in real time, avoid bunker plugging, reduce excess air without lowering carbon conversion and increasing the generation of nitrogen oxides, and better control flue gas desulfurization processes.

CONAC demonstration

To demonstrate CONAC technology under actual power station conditions, EPRI and TVA jointly planned and sponsored a demonstration program and built special facilities for comprehensive testing of a prototype CONAC instrument system. The principal goals of the demonstration were to determine CONAC's accuracy and precision (repeatability) by recirculating well-characterized lots of coal; to demonstrate CONAC's ability to perform in a power station environment; and to operate CONAC continuously in an on-line mode and demonstrate the value of the information obtained. Bechtel was the testing contractor.

The three planned project phases have been completed. Phase 1, field acceptance testing, was designed to verify laboratory results at the Paradise installation. Phase 2, PGNAA testing, involved first calibrating the instrument by using boxed coal standards and then assessing CONAC's accuracy and precision. Both of these phases are summarized in the November 1984 *EPRI Journal* (p. 49). Phase 3, high-count-rate testing, began in March 1984 and involved upgrading the CONAC electronics package to reduce the reporting time from 20 to 5 minutes; calibrating the CONAC instrument systems; testing CONAC on bulk coal samples as well as boxed, stationary coal standards; characterizing CONAC's ability to respond to changes in coal quality; and operating CONAC on-line.

The first results from the phase 3 testing of dynamic coal samples (i.e., samples circulated through CONAC for long periods) were poorer than anticipated. After analyzing the data, the researchers concluded that because the nuclear characteristics of the Paradise

Table 1
CONAC TEST RESULTS AND PERFORMANCE GOALS

	RMS Accuracy*			Precision (standard deviation†)		
	Test Result	Pass/Fail Criterion	Long-Term Objective	Test Result	Pass/Fail Criterion	Long-Term Objective
Carbon (wt%)	1.31	5.0	2.0	1.88	4.0	1.25
Hydrogen (wt%)	0.12	0.5	0.1	0.02	0.2	0.1
Ash (wt%)	0.99	2.0	1.0	0.49	0.5	0.2
Sulfur (wt%)	0.13	0.25	0.1	0.11	0.15	0.05
Nitrogen (wt%)	0.05	0.4	0.2	0.10	0.3	0.1
Moisture (wt%)	1.18	2.0	1.0	0.16	0.5	0.5
Heating value (Btu/lb)	106	400	175	123	300	100

Note: The accuracy results are for four coal samples; the precision results, for one sample.
*Expressed as CONAC's deviation from the ASTM result.
†One sigma.

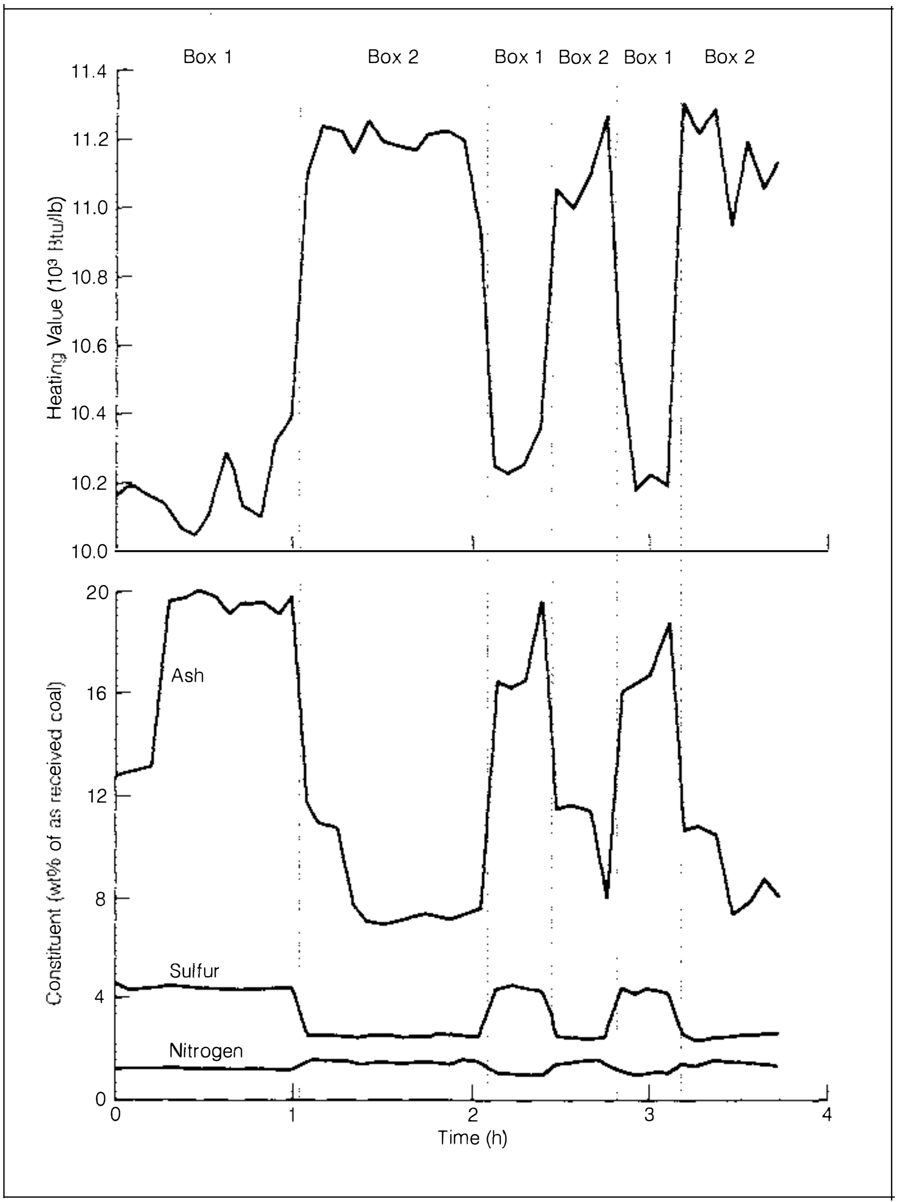
coals differ from those of other coals in the TVA region, the calibration was slightly skewed. They also concluded that the californium neutron source was moving in its mounting and that the moisture meter and the densitometer were not well calibrated. These conclusions led to the development of improved calibration techniques, including on-line techniques for the moisture meter, densitometer, and hydrogen sensor. The californium source mounting was modified to reduce or eliminate the source movement.

After these improvements and modifications were made, CONAC was retested with moving coal samples in the winter of 1985–1986. Four samples were used: a Paradise raw coal, a Paradise clean coal, and two blends of Paradise clean and raw coals. Each lot was carefully sampled, and the traditional ASTM laboratory determinations of the coal's composition were compared with CONAC's determinations.

Table 1 shows CONAC's root-mean-square (rms) accuracy for the four tests (which indicates the extent of deviation between the CONAC and ASTM analyses), along with the TVA–EPRI performance goals. All pass/fail criteria were met, and all long-term objectives were met or very nearly met. From these tests it was concluded that CONAC is capable of producing accurate analyses for the Paradise coal supply. The test data set has one major problem: serious questions exist about the consistency of the laboratory ASTM moisture reports. The problem is under investigation.

Two tests were conducted to evaluate CONAC's ability to respond to changes in coal quality during dynamic operation. In the first, which was designed to provide a qualitative measure of this ability, incremental amounts of clean coal were added to a recirculating coal lot. In the second, which was designed to provide a more quantitative measure, two boxes containing coal of known composition were alternated. CONAC responded immediately and accurately to changes in coal quality in both tests. Figure 3 presents results from the second test.

Figure 3 Boxes of two well-characterized coal samples were alternated to test CONAC's ability to respond to coal quality changes in dynamic operation. As indicated by these heating value and composition results, CONAC responded immediately and accurately to the changes.



Operating experience

TVA's experience has demonstrated that a sophisticated instrument system can be successfully operated in a power station environment. CONAC's availability over the testing schedule exceeded 91%. Of the downtime, nearly three-quarters can be attributed to failures of the CONAC computer data storage system. This prototype system was not hermetically sealed, as a commercial unit would be, and four years of airborne dust made disk malfunctions a common occurrence. TVA has prepared specifications for a new computer system, including hermetically sealed data storage media, which should further improve CONAC's availability.

The system itself has proved easy to operate. All operational commands are implemented from a computer keyboard. Maintenance and adjustments are straightforward and can be performed by site personnel; only major equipment failures or repairs require specialized electronics knowledge.

TVA is now operating CONAC on-line on sampled coal from the Paradise cleaning plant. The system routinely operates unattended overnight. Evaluations are also under way at EPRI and TVA to determine how best to apply the information that CONAC provides. TVA and Bechtel are preparing a report that details the results of the demonstration.

The basic technologies making up the CONAC system can be used individually—or in simpler combinations than in CONAC—for control applications that require less information. One example of a simpler, CONAC-derived on-line analyzer is the sulfur meter at Detroit Edison, which uses only PGNAA technology and measures only coal sulfur concentration. Moisture and ash analyzers are other examples. Currently EPRI is developing projects to demonstrate specific applications for the CONAC system and simpler on-line analyzers derived from it. *Program Manager: Frederick Karlson*

R&D Status Report
ELECTRICAL SYSTEMS DIVISION

Narain G. Hingorani, Vice President

TRANSMISSION SUBSTATIONS

Bubble evolution in transformers

Temperature excursions caused by loading changes occur with varying degrees in all transformers. However, when rapid increases in load occur, the resultant higher temperature in the windings will drive out moisture and gases from the insulation When the oil becomes oversaturated with the moisture and gases, bubbles form. These bubbles are a cause for concern because wherever they impinge on dielectric material they result in a localized area of high stress on the insulation. If the local voltage stress exceeds the dielectric strength of the material, a breakdown occurs. In an extreme case, the transformer could fail.

Two contractors have been working to develop a basis for predicting circumstances that can lead to the generation of bubbles in oil/solid insulation systems or, conversely, for identifying circumstances that will surely avoid their generation.

Westinghouse Electric Corp. has selected a series of experimental studies to establish some of the conditions that result in bubble formation and the resultant deleterious electrical or physical effects (RP1289-3). The tests being run include transformer overload cycling, tests on thermal models, and dielectric tests on electrical models; finally, several transformers will be tested to destruction under bubbling conditions.

Observations to date in the transformer tests show that conditions leading to bubbling in power transformers can be duplicated in the laboratory and that there appears to be a correlation between hot spot location and bubble evolution. Quantitatively, the dissolved gas concentration appears to affect bubble evolution. In the thermal models, moisture, hot spot temperature, and pressure in the gas space are interdependent and influence the evolution of gas bubbles. In the electrical model tests, a marked reduction in 60 Hz and full-wave-impulse dielectric strength was found when bubbles were present.

The second contractor, General Electric Co., recently developed a concept for a simple computer model that provides useful insights into the occurrence or avoidance of bubble formation in oil/paper transformer insulation systems (RP1289-4). This concept was described in an IEEE paper presented at the 1984 Summer Meeting of the Power Engineering Society.

As pointed out in the paper, the confidence in predictions from the model would be increased if there were reliable data on the behavior of the most important gases, particularly water vapor, in the transformer oil/cellulose system in the 125–170°C temperature range.

Scenarios have already been explored in prior General Electric work on bubbling resulting from supersaturation by gases because of the desorption of water from cellulose, the degradation of paper, and a combination of these events. The new data generated in this contract will be input to the model to revise predictions for the possibility of bubbling. These predictions will be compared with actual overloading practices to define circumstances in which transformers become vulnerable. *Project Manager: Gilbert Addis*

By-products of utility fires

As PCB use has been decreasing at an accelerating pace, numerous related problems have become apparent—for example, formation of polychlorinated dibenzofuran (PCDF) and other physiologically active materials in PCB fires; the difficulty of finding substitute insulating fluids; the potential hazards from combustion products of substitute fluids, both contaminated and uncontaminated with PCB; and the potential hazards from combustion products of other insulations or materials exposed to fires (solids or gases). As can be seen, much of the emphasis has moved to oxidation and combustion products.

Some of the EPRI work on these problems has addressed the following.

- Formation of PCDF in Askarel and contaminated mineral oil equipment (RP2028-5, -10)
- Pyrolysis and combustion of insulation fluids contaminated with Aroclor 1254 (RP2028-4)
- State-of-the-art review: PCDD and PCDF in utility equipment (RP1263-11, CS-3308)
- Arc by-products of perchloroethylene (RP 1499-4, -5, EL-4497)
- Maintenance and handling of perchloroethylene-filled utility equipment (RP1499-6, EL-4407)
- Toxicity profiles of PCB substitutes (RP 2378-8, EA-3567)
- Partial and complete combustion products of transformer insulation liquids (RP2028-11)
- State-of-the-art review of PCB substitutes and their pyrolysis/combustion products (RP 2028-12, EL-4503)

In a new project EPRI plans to expand from the initial pyrolysis and combustion work on substitute transformer fluids to solid, gaseous, and other liquid insulations (i.e., capacitor fluids). If necessary, this work will also cover a limited number of other substances if they are potential contributors to toxicity hazard in utility fires.

Three contractors have been chosen for this effort: Midwest Research Institute (MRI), University of Dayton Research Institute (UD), and General Electric. Initially, MRI will search the literature for prior work (RP2028-15). Both MRI and UD will make pyrolysis and combustion tests and analyses (RP2028-16). Analysis for trace compounds that may present an unusual hazard will be conducted if it seems desirable. General Electric will make recommendations on utility use patterns and will supply many of the materials to be tested (RP2028-17). As data become available, UD will also use its thermodynamic and kinetic modeling techniques to develop methods for predicting pyrolysis/combustion by-products of existing and new materials.

The project is expected to take 18–24 months for completion. *Project Manager: Gilbert Addis*

DISTRIBUTION

Pole hole drilling in rock

Poles to support overhead electrical circuits occasionally must be set in rocky terrain that cannot be penetrated with conventional mechanical pole hole diggers. Currently available alternative methods, such as jackhammer or blasting (where permitted), are time-consuming and cost much more than $300 per hole.

In early 1983 a project was started with Foster-Miller Associates, Inc., to develop methods and/or equipment that would reduce the cost of providing pole holes in rock by at least 50% (RP2209). The project included concept development, full-scale prototype design and fabrication, and field demonstrations. Investigation of a variety of approaches resulted in a percussive kerf-and-break concept for design and fabrication of a prototype. Preliminary trials were conducted, and field demonstrations are under way.

The percussive kerf-and-break core barrel (Figure 1) is mounted in the same position as the normal mechanical rotary auger on a standard line digger-derrick. Briefly, the 6-ft (1.8-m), double-walled core barrel supports two hydraulic percussive drills mounted diametrically opposite each other; drill stems extend the length of the core barrel in the annular space between the two walls. While the drills are operating, the entire core barrel is rotated by the hydraulic digger motor so that an annular kerf is cut in the rock. After reaching the desired depth, the core barrel is removed, and the remaining core is broken out by using a hydraulic wedge, or splitter, that is placed in the kerf. Hydraulic oil supply and return for the drills, the compressed-air supply, and a vacuum return for cooling the drill stem and bits and for removing the spoil, enter and exit the rotating core barrel through appropriate swivels. The digger's power take-off hydraulic piping sytem was modified to accommodate the system.

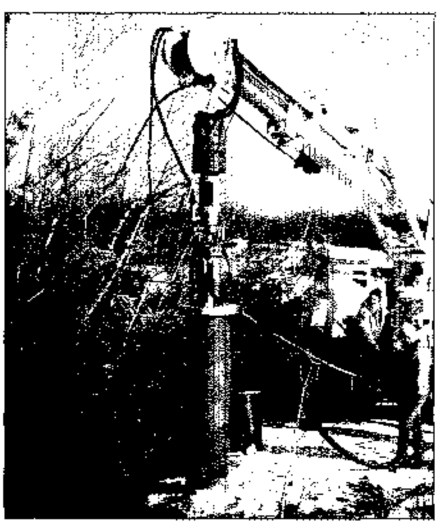


Figure 1 Prototype of a rock hole driller that attaches to a standard digger-derrick line truck.

Early trials in a granite (30,000 lb/in^2 [206.8 GPa] compressive strength) quarry were successful. Field demonstrations are being conducted in other types of rock formations to better evaluate the overall capability of this system. *Project Manager: Thomas Kendrew*

Grounding cable ratings

The prime rule when working on power circuits is "work it hot or ground it out" (Figure 2). For the lineman to be protected in the event of an accidental energization of a line, the grounding cables placed on that circuit must shunt the current to ground until the breaker or fuse operates. The objective of this project is to determine the short-circuit current capacity of commonly used ground cables (RP2446-1).

Initial testing was at the Ontario Hydro high-power laboratory on 1/0 copper cables with strandings and jackets in common use. Current values were selected to produce failure in the 6–60-cycle range, and the tests were repeated to produce a statistically significant fusing value. The results were then compared with values obtained from two methods used to calculate the time-temperature characteristics of copper conductors. The most widely used calculation method, Onderdonk's formula, was shown to be very conservative. A more recent method, based on theory developed by V. T. Morgan, showed very close agreement for short fusing times but was conservative for longer times.

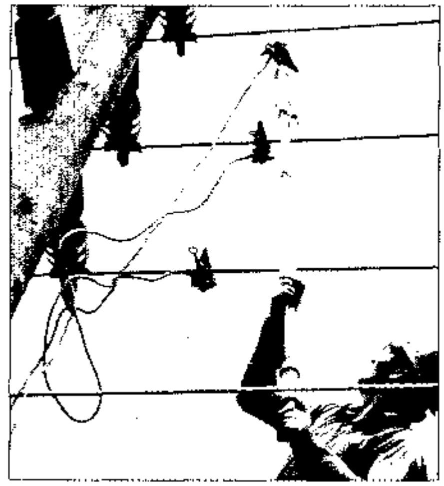
Using the results of the comprehensive testing on 1/0 copper cables, Ontario Hydro is currently developing a computer program, which is based on a modification of Morgan's formula, to predict the failure time for any cable size from 1/0 to 350-kcmil copper. The short-circuit tests on 2/0-, 4/0-, 250-, and 350-kcmil copper cables will check the accuracy of results from the new computer program.

In addition to testing single copper grounding cables, the failure points of two 1/0 copper cables connected in parallel will be determined. Also, 4/0 aluminum cables will be tested to failure.

Some of the observations to date include the following.

- Commonly used analytic methods to determine cable ratings are generally conservative.
- If a full dc offset occurs, these calculations may not be conservative.
- Conventional jacket materials have little effect on cable performance.

Figure 2 A lineman installs protective grounds on a deenergized circuit prior to working on the line.



- A properly designed ferrule has to be used to achieve the full rating of the cable.

A final goal—one that may be difficult to achieve—is to develop an improved cable design; that is, a design that will increase the cable rating without increasing the cable's weight or cost. A final report and computer program will be available in late 1986. *Project Manager: John H. Dunlap*

UNDERGROUND TRANSMISSION

Underground obstacle detection and mapping

Locating and accurately mapping underground facilities in city streets are of vital importance to utilities. Such mapping ensures against third-party damage to utility equipment and reduces or eliminates the possibility of dangerous gas pipeline or power cable incursions.

Because of the wide variations in soil conditions, a radar-only-type approach to detecting pipes is difficult. EPRI initiated a ground-penetrating radar project in the hope that such a system would provide adequate signal strength under various soil conditions and overcome clutter problems by using filters and signal processing techniques by means of a computer (RP7856). Digitizing sampled radar return signals and using a computer to enhance signal-to-noise values appeared to be the solution to locating pipes. Unfortunately, the system did not function as expected because excessive soil moisture and mineral content caused drastic attenuation of the signal.

The computerized radar system worked to a limited degree and only under ideal soil conditions. Although improvements could be made, the costs involved versus the benefits to be gained do not justify further pursuit of this technology at this time. *Project Manager: Thomas J. Rodenbaugh*

Backfill materials

The allowable current ratings of buried electrical transmission cables are based on the maximum permissible temperature at the interface of the cable surface and the surrounding ground. If the backfill in the trench surrounding the cable is unable to conduct heat away rapidly, high cable temperatures may develop, leading to thermally induced failure.

There is a need, therefore, to understand the mechanisms occurring in soils that contribute to and affect heat transfer, especially when subjected to high temperatures for prolonged periods. Research has been ongoing for several years to characterize and understand thermal processes around buried cable and is now complete (University of California at Berkeley, RP7841).

The most recent results (to be published shortly in a phase 4 final report) deal with a series of field tests on three full-scale simulated buried cables. These field installations were used to obtain data on moisture migration and thermal instability versus soil dryout caused by cable heating. The three field test cross sections (Figure 3) are typical of utility requirements, as are the pipe diameters of 4, 8, and 16 in. Over a hundred 8-in-long in situ thermal needles were fabricated and distributed throughout the trench backfill and surrounding native soil for periodic temperature and thermal resistivity measurements. Gypsum blocks were installed for measuring water content and dryout regions. Needles or probes obtained and plotted thermal, moisture, and resistivity profiles that represented over one year of field operation. These profiles were then compared with predictive techniques (algorithms), and two separate IBM PC–compatible programs resulted.

The cables reached thermal instability during field tests, and the results were consistent with laboratory tests. Other key conclusions fully described in the phase 4 report dealing with thermal stability are as follows.

- The higher the initial water content in the soil is, the longer the time to onset of thermal instability.
- Instability could be induced for any initial water content, which contradicts the critical moisture content theory.
- The higher the initial ambient soil temperature is at time of cable heating, the longer the time to reach instability.
- The time to instability for a given heat input rate varies directly as the square of cable diameter.
- As heat input rate is increased, the cable surface temperature at which thermal instability occurs is also increased.

Results of the entire 11-year research project are discussed in three reports published by EPRI: EL-506, EL-1894, and EL-4150. *Project Manager: Thomas J. Rodenbaugh*

POWER SYSTEM PLANNING AND OPERATIONS

Fast stability analysis

For many years researchers have attempted to replace the traditional step-by-step power system stability calculation method with a direct method based on energy balance concepts. In theory, the direct method can provide more information to the analyst than can traditional methods and requires much less computation time. Until several years ago, however, direct calculation methods failed when applied to anything but unrealistically small power system models.

The November 1984 issue of the *EPRI Journal*, page 55, reported progress in the direct calculation of power system stability for large, realistic networks (RP2206). Testing with a 17-generator network model showed a 10-fold saving in computation time, compared with traditional methods. When network models contained more than 100 generators, however, traditional methods were faster than the direct method.

Research since then demonstrated the feasibility of direct transient stability calculation of networks having up to 225 generators. The accuracy, reliability, and speed of the technique have been tested with over 2000 scenarios, representing over 20 different power system models.

However, when testing larger networks, the researchers found that the direct method still is more time-consuming than traditional methods for modeling networks having over 100 gen-

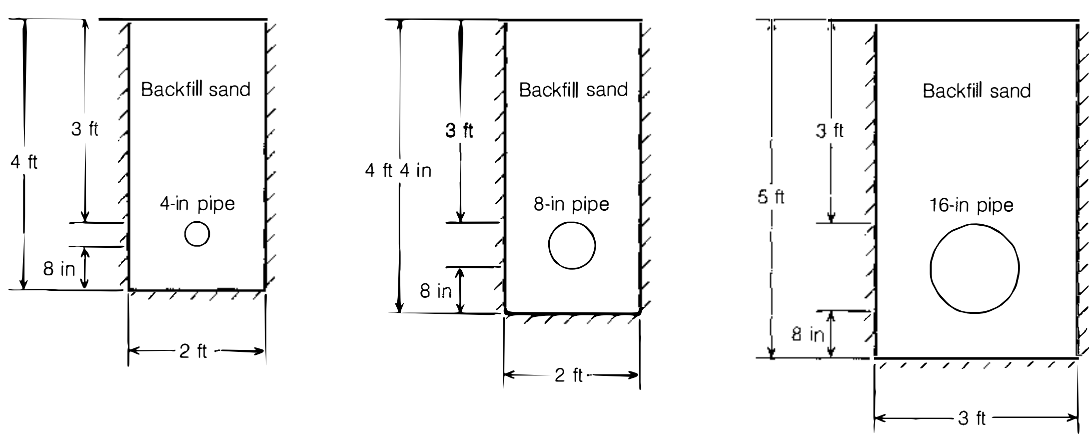


Figure 3 Design cross sections for field-test buried-cable trenches. Standard utility-size trench dimensions are shown for each pipe size. Surge backfill sand was tamped in layers, as is usual in utility practice.

erators because of some bookkeeping aspects of the direct method. This limits the applications of the direct method if computation speed-up is the only consideration. But the additional information provided by the direct-stability calculation method makes it attractive when the relative stability of many plans must be compared or when stability limits must be calculated very quickly, as is the case in power system operation applications. The software and documentation are therefore being prepared for distribution in mid 1986.

Research is now under way to speed up the direct method and to overcome several important modeling limitations inherent in this method. Experiments show that a many-fold computation speed-up can be achieved by eliminating some of the bookkeeping. Early results hold the promise that models for excitation systems, HVDC, and loads may soon be provided. These improvements will be distributed as they become available and are tested. *Project Manager: James V. Mitsche*

Near-term enhancements to EGEAS

The first phase of RP1529 developed a computer program, EGEAS (electric generation expansion analysis system), to help utility planners carry out the three primary analysis functions in generation planning—optimal generation expansion, reliability analysis, and production cost calculations. The second phase of the project was initiated with Stone & Webster Engineering Corp. in September 1983 to develop the following enhancements to EGEAS.

- A model for the economic utilization of storage units
- A model for must-run units and spinning reserve requirements
- Modifications to the dynamic programming optimization option, including a restart feature and a file-merging capability
- Expansion of the report generator program's capabilities to provide information on loading order, maintenance schedules, storage units, and neighboring system characteristics
- Incremental cost information in the production cost models
- Energy purchase/sales model
- Representation of storage units in Bender's decomposition optimization option

A revised EGEAS (version 2.0), incorporating the first four enhancements, was distributed to more than 65 member utilities in February 1985. EGEAS 2.0, developed for an IBM computer system, was converted to run on Prime computers in May 1985. Both the IBM and Prime copies of version 2.0 are available from the Electric Power Software Center. The last three enhancements were completed in December 1985 and are included in EGEAS 3.0. Both the IBM and Prime copies of EGEAS 3.0 are expected to be distributed through EPSC in early 1986.

The EGEAS Users Group was formed in September 1983 to provide a forum for an exchange of experience. Six quarterly newsletters and three meetings have been held so far as part of the Users Group activities. EPRI retains Stone & Webster to maintain the program and to provide assistance to EGEAS users for the installation and execution of the program and the interpretation of the test case results. *Project Manager: Neal Balu*

VAR optimization

A number of methods have been proposed for VAR optimization, but serious shortcomings have prevented them from fully exploiting the VAR and voltage control capabilities of currently available devices. Further, existing methods do not have the capability to compute solutions for large-scale (1500 buses or more) utility systems. The objective of this 20-month project was to focus on the development of advanced optimization methods for VAR allocation in large-scale utility systems (RP2109). A computer program is being developed to determine the size and location of reactive power sources.

The project has developed a two-level approach for VAR optimization: level 1—identification of the optimal dispatch of available reactive sources; level 2—determination of the least expensive patterns of adding VARs. The two-level approach was implemented in the prototype VAROPT computer program for analyzing large-scale power systems. The program has been successfully tested on simulated bulk power systems of various sizes and characteristics.

The VAROPT program was tested for validation by Southern Company Services, Inc., Ontario Hydro, and British Columbia Hydro, and it is now available for distribution from the Electric Power Software Center. *Project Manager: Neal Balu*

Solvent extraction of PCBs from contaminated mineral oil

Several years ago, General Electric investigated several processes for reducing PCB (polychlorinated biphenyl) contamination in mineral oil (RP2028-1). Because sodium treatment was then being brought into commercial operation by a number of organizations, EPRI chose a solvent extraction process as a potential alternative.

PCBs can be removed from transformer mineral oil by mixing the oil with an immiscible liquid in which PCBs are soluble. PCBs will be removed from the oil into the extraction solvent until equilibrium is established. If the partition coefficient is one, half of the PCBs in the oil will be dissolved into an equal volume of extraction solvent initially containing no PCB.

Oil-liquid systems with higher partition coefficients require less solvent to reduce the PCB content of oil by a given amount. Unfortunately, large partition coefficients for oil-solvent systems are unlikely, and the amount of extraction solvent needed to remove PCBs will be large. Any practical process will require reuse of the solvent after removal of the previously extracted PCBs. This can be done by using an extraction liquid that has a boiling point well below that of PCB (~275°C and up). The solvent can be recovered by distillation, leaving the accumulated PCBs in the still bottoms for removal and final incineration.

The work reported here is based on extraction of PCBs by the monomethyl ether of diethylene glycol—methyl Carbitol (MeC).

A small-scale (10 gal/h, 37.8 L/h) demonstration plant was designed by Veridyne, Inc. and put in place to establish the technical feasibility of the extraction process and to evaluate the relation between controllable process parameters and efficiency in a continuous operation (RP2028-1, -3). This enabled the contractor to estimate the magnitude of the process costs. A commercially available agitated multistage countercurrent extractor was used (York Process Equipment Co.). Oil containing PCBs was fed into the column near the bottom, and the extracted product was removed at the top of the column. PCB-free MeC was introduced into the column near its top and removed with its loading of dissolved PCBs near the bottom. The extract was fed to a vacuum distillation column where the MeC was distilled from the PCBs and oil. The MeC was recycled to the extraction column and a PCB-enriched oil fraction accumulated in the distillation column bottoms. Loss of no more than 1% of the oil was set as a goal in this study. This would result in a PCB concentration in the distillation column bottoms of roughly 100 times the concentration in the feed. A residue concentration as high as 5% PCB could be reached.

On the basis of the pilot plant results, Georgia Power Co. has a contract to build a 120-gal/h (454-L/h)—nominally 500,000-gal/yr (1893-kL/yr)—extraction plant (RP2028-14). Georgia Power plans to operate at 98% extraction efficiency and thus reduce the average PCB level of contaminated oil in its system to 2% of its present level.

Equipment designed by Veridyne is now onsite and operation is expected to commence in June 1986. *Project Manager: Gilbert Addis*

R&D Status Report
ENERGY ANALYSIS AND ENVIRONMENT DIVISION

René Malès, Vice President

PRISM: PRIORITY SERVICE METHODS

Operating in an increasingly competitive environment, utilities today are confronted with unprecedented challenges. In view of this situation, EPRI recently initiated the preliminary phase of a project called Prism (RP2801), which seeks to create a host of viable new options that will enable utilities to be more responsive to customers' needs and therefore to be more competitive. The first phase of the project entails a study to explore ways of unbundling, or separating, electricity into products with different levels of reliability. Summarized here are the preliminary results of this ongoing study, whose primary objective is to develop a sound foundation for future research in this new area.

Traditionally, electricity delivery has been a homogeneous and reliable service. Over many decades, progress in power generation and transmission technology has contributed significantly to efficiency improvements in electric power systems. The development of interconnected, centrally dispatched systems has enabled utilities to achieve further efficiency gains by pooling loads that vary randomly over time and location and by taking advantage of the different operating and cost characteristics of various supply options. As a result, utilities have been able to provide all customers with highly reliable electricity service at reasonable prices.

From the consumer's perspective, reliability has always been one of the most important criteria measuring the quality of electricity service. However, new end uses and technologies have constantly created new reliability needs. Electricity, first used only in street lighting over a century ago, has now become the lifeblood of a modern society, with countless applications. Recent studies indicate that the value different customers place on service ranges widely—from several pennies to tens of dollars per kilowatthour. This diversity clearly indicates that different consumers require very different levels of service reliability.

Priority service is a special form of product differentiation that expands the quality dimension of electricity service. The basic idea is to unbundle electricity service into various levels of service reliability and to give consumers an opportunity to select, from a menu of choices, plans that best meet their individual needs.

Product differentiation is a corporate strategy that promotes customer satisfaction when customers' needs are diverse. It is applicable not only to product industries but also to service industries. In fact, differentiation with respect to service conditions has been quite common in such industries as financial services, transportation, and telecommunications. Drawing on the experience of these industries, the EPRI study has adopted an approach that addresses four key considerations: understanding consumers' needs and their diversity, identifying product attributes that can be economically unbundled to meet those needs, understanding the ability of the electricity system to deliver diverse products, and designing mechanisms for practical implementation.

If the research shows that priority service is practical, there could be several advantages to both utilities and their customers. A well-designed program for implementing priority service could benefit all customers, as well as the utility. Because customers have different needs, some would be willing to tolerate the inconvenience of more frequent power interruptions in exchange for a lower price, and others would be willing to pay a premium for even more reliable service than regularly provided. By allowing customers to make their own selection, priority service would enable the costs and availability of service to be matched more closely to their needs and thus would result in lower total costs.

Priority service, if practical, could improve consumer satisfaction. In the event of a power shortage, it would provide an efficient and equitable procedure for allocating scarce supply and reducing the total shortage costs: service to customers with lower interruption costs could be curtailed before service to those with higher interruption costs. Priority service would also enable customers to select plans that minimize their total costs—that is, their electricity bills together with their interruption losses.

Another possible benefit is that priority service could promote a wider variety of choices regarding generation. It would give the utility greater flexibility to plan future capacity additions and to improve capacity utilization by marketing power from otherwise unused capacity. Moreover, it would make it possible to treat load control options stipulated in the service contracts as a reservoir of reserve capacity that could be used to balance the load and thus reduce spinning reserve requirements. Finally, priority service could promote efficient energy use by giving customers incentives to purchase equipment and appliances that match the levels of service reliability they choose.

Priority service could be offered through a combination of technological options. In case of a power shortage, for example, a utility might exercise load-shedding control over part of the load of customers who choose lower-priority service. Conversely, customers who purchase premium service might be provided with backup generators, fuel cells, local energy storage, uninterruptible power systems, or multiple feeders.

Priority service critically depends on metering and control devices. Recent developments in microelectronics enable sophisticated metering and control devices (e.g., Calms, Transtext) to be mass-produced economically. These microelectronic devices can offer utilities additional benefits, such as remote reading of billing information, and can be used in connection with other services, including entertainment, financial, security, and banking services.

What distinguishes the priority-of-service concept from earlier demand-side management initiatives is its breadth. Instead of curtailing service to specific customers or end uses in return for a special rate, this approach would present all customers with a menu of reliability levels and corresponding rates. The scale of implementation makes approaches based on individual negotiations impractical. What is required is a mechanism for providing information and incentive structures that can minimize the costs and risks of implementation.

A central element of such a mechanism is the design of a menu that presents service reliability and discount options. Priority service product selection and pricing characteristically involve an iterative process (Figure 1). Each customer, faced with a given menu, selects a service plan on the basis of his own valuation of service, which usually cannot be directly observed by the utility. The resulting market penetration will reveal, perhaps only imperfectly, the distribution of consumer valuations, which is a useful piece of information for designing the menu.

For its part the utility needs to consider a number of important factors, including system reliability, revenue requirement, costs of service, customers' behavior, and competition. In the short term, given a fixed capacity configuration, the relative prices of the various service priorities are adjusted so that the customers' choices will result in a balanced distribution of low-priority, regular, and high-priority loads. (Regular service offers the same level of reliability as would be provided without priority service.) The distribution must have sufficient low-priority loads that the utility can provide more reliable service to high-priority customers and must, at the same time, have sufficient high-priority loads that the utility can recover its capacity costs and maintain its financial integrity. In the long term, the capacity configuration can be adjusted so that priority charges will reflect the associated capacity and operating costs.

Priority service is closely related to spot pricing; indeed, spot pricing is a special form of priority service. Both promote economic well-being by adapting rates to the availability and costs of supply as well as to consumers' valuations of service. The key difference is the time frame. Spot prices are revised continually. Priority service can be offered as a forward contract over any specified period. In principle, each priority class can be associated with a cutoff price level so that service is curtailed when, and only when, the spot price exceeds this level. And the price charged for each priority class is the expectation of what the spot price would be for power obtained under the selected priority of service.

The implementation of priority service could take several organizational forms, which have considerably different implications for costs and risks. Three forms have been investigated in the EPRI study. Demand subscription service, which is a form pioneered by Southern California Edison Co., allows each consumer to select different reliability levels and corresponding rates for different increments of his load. In such a scheme, the responsibility for estimating the chances of interruption and for interpreting contractual obligations rests primarily with the utility.

In the second form of implementation studied, consumers purchase service insurance and can expect to be compensated for an interruption by an amount that depends on the insurance premium paid in advance. Then, during power shortages, the utility will first interrupt the service of those customers who selected the lowest coverage. This approach requires relatively little monitoring and control. The insurance can be provided by the utility or by a third-party underwriter.

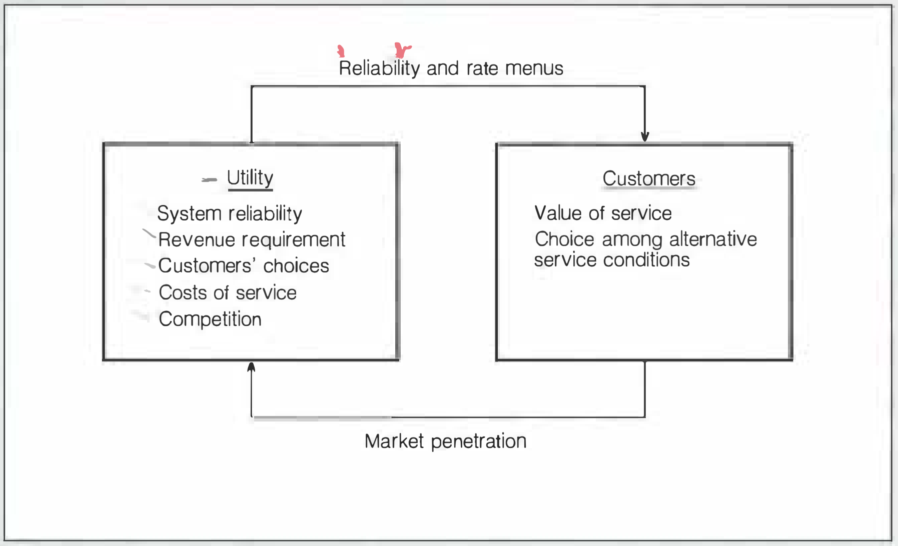


Figure 1 Priority service product selection and pricing. On the basis of the factors listed, a utility designs menus of reliability levels and corresponding rates, from which customers select the desired level of service. The customers' choices, as reflected by market penetration, help the utility refine the menu design.

In the third implementation form, each consumer buys priority points, which are then assigned to load segments or circuits. Thus the utility is relieved of the task of designing a reliability and rate menu. In an emergency the utility simply first curtails those load increments or circuits assigned the fewest priority points. A market will be created to allow consumers to exchange their priority point holdings. In this approach the burden of assessing the likelihood of interruptions is transferred to the market maker and participants. The market transactions of priority points will provide relevant information about the distribution of consumer valuations and a direct indication to the utility of whether capacity expansion is justified.

Priority service is truly broad in scope. By unbundling electricity service, utilities would face the prospect of creating an entirely new market from first principles. Nearly every aspect of utility business could be affected. Priority service seems likely to be another step in the evolution of the industry. A growing number of utilities are beginning to experiment with alternative forms of priority service. EPRI's preliminary study provides useful concepts and insights that contribute to a better understanding of the issues involved. It also raises important questions that must be addressed in future research. Research planning is under way at EPRI to develop the concept into practical methods. *Project Manager: Hung-po Chao*

RISK MANAGEMENT METHODS FOR UNDERGROUND STORAGE TANKS

The potential effects of leaks in underground storage tanks containing hazardous materials or petroleum products have motivated a major regulatory effort by the federal government and the states. When leaks in underground tanks occur, costly measures may be necessary to decontaminate the soil, groundwater, and adjacent structures or to provide alternative sources of drinking water. The electric utility industry is a major user of underground storage tanks, primarily for storing fuel for vehicle fleets. A survey by the Edison Electric Institute (EEI) estimated that utilities own more than 15,000 tanks. Managing the risks associated with these tanks is difficult because of the large number of management options, the wide variety of tanks and sites, and the enormous uncertainties in the potential for leaks and damage. To help utilities with this task, EPRI initiated the development of a system for underground tank risk management (RP2595).

Underground storage is a common solution to the problems of fire protection and space availability in storing gasoline, other petroleum products, and hazardous materials. Underground storage tanks sometimes leak, however, and their contents can contaminate the soil, nearby structures, and groundwater. Two common causes of leaks are corrosion (in the case of bare steel tanks) and improper installation; another source of leaks is the piping systems associated with tanks. Because these leaks are out of sight, they can release materials for long periods before a problem is detected.

Following the reauthorization of the Resource Conservation and Recovery Act in late 1984, EPA initiated a major effort to regulate underground storage tanks containing hazardous materials or petroleum products. The regulations require users to conduct extensive surveys to identify current and past tank populations and to list the tanks with state agencies. The regulations also prohibit the installation of new tanks without extra measures to protect against leaks. Additional EPA regulations are being developed, and several states have enacted their own regulatory programs that require protection for new tanks and extensive monitoring and testing.

The problem facing utilities

According to an EEI survey, most tanks owned by the electric utility industry are unprotected steel tanks over five years old. Important questions for utilities are how to manage the risks from these existing tanks and how to select new or replacement tanks. Although health risks from contaminated groundwater are unlikely because the threshold of human detection of gasoline is quite low, these tanks still pose a significant economic risk to utilities.

When leaks occur, the costs of remedial action can range into the millions of dollars if alternative sources of drinking water must be provided or if damaged structures must be replaced. The expense of programs to test and monitor tanks and/or to replace them with tanks considered less likely to leak must be balanced against the uncertain but potentially very large cost of leaks.

Managing these risks is a difficult undertaking, in part because of the number and complexity of the decisions to be made. There are a variety of tank types, monitoring systems, testing strategies, and tank retirement policies, and evaluations are complicated by interdependencies among the options. For example, the relative desirability of a strategy that removes tanks early to decrease the chance of a leak depends on the likelihood that the replacement tank will leak.

Numerous uncertainties further complicate the analysis. Is a particular tank leaking? Will it leak soon? How reliable is the monitoring system? How far will the leak spread? How much will it cost to clean up? Also, because most utilities have many tanks of different types, locations, and ages, keeping track of them and systematically implementing policies can involve large data management efforts. Ultimately, the utility decision maker must balance the risks and costs of the management alternatives across all the utility's tanks in a way that makes the best use of limited budgets.

To help utilities manage the economic risks associated with tank use, EPRI contracted with Decision Focus, Inc., to develop the underground tank risk management system. The system is intended to facilitate cost-effective tank management and minimize the costs and effects of leaks. It takes the form of decision support software tools that can be operated on personal computers by utility staff. Decisions addressed by the system include the selection of replacement tank technologies, the specification of tank testing and monitoring programs, and the determination of optimal timing for tank replacement. The system has the data management capability to help track the status of a utility's tank inventory and to help manage the utility's overall budget for tank risk management.

System structure

The underground tank risk management system has three components. The user interface performs general data entry and retrieval functions and is used in setting priorities among tanks and defining decisions on specific tanks. It facilitates user interaction with the other two system components, the data base manager and the tank risk management model.

The data base manager organizes and stores information on the utility's tanks, tank sites, and remedial activities; the results of previous analyses; and general company data. This information is transmitted to and from the tank risk management model as needed.

The tank risk management model is the core of the system and also its most complex part. Given data characterizing a particular tank and site, the model determines the current best decision on whether to replace the tank and identifies optimal future decisions on the basis of projected testing and monitoring results. It also calculates such key results as the expected life-cycle costs of the tank under the optimal strategy, the expected remaining life of the tank, the likelihood of a leak, and the expected costs and effects of a leak. The input data include the tank's type, age, and risk-of-leak profile; the sensitivity of its location to damage; the costs and risk-of-leak profiles of replacement tanks; and the costs and accuracy of tank testing technologies.

Life-cycle costs are calculated over a suitably long time horizon, and the same period is used for all options to ensure a consistent comparison. Life-cycle costs include day-to-day and year-to-year operating costs (e.g., for monitoring and testing the tank); the cost of eventual replacement of the tank, either as a measure to prevent leaks from occurring or as a necessity at the end of the tank's useful life; and the costs of a leak, including site mitigation, damage awards, and installation of a replacement tank. A leak's costs are weighted by the probability of its occurrence. In general, expenditures for early tank replacement or increased monitoring and testing are returned through lower expected costs from leaks.

Six submodels perform the calculations of life-cycle costs in the tank risk management model (Figure 2). The tank operation submodel considers decisions about when to replace

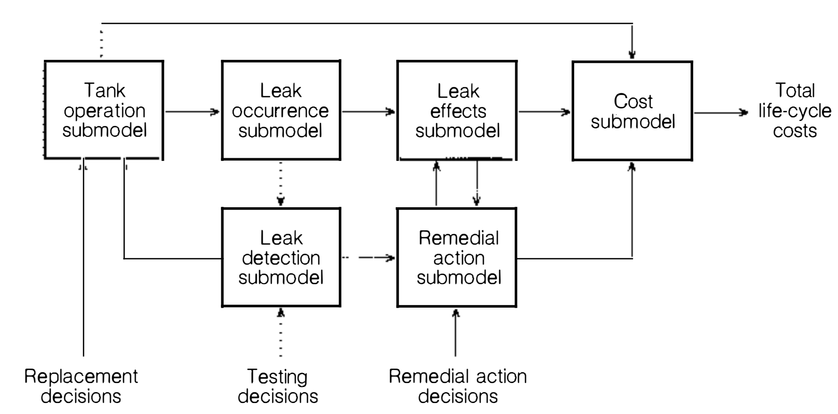


Figure 2 The tank risk management model estimates the costs of alternative strategies for managing underground storage tanks. It addresses decisions on tank replacement timing and technologies, tank monitoring and leak detection testing, and remedial action—taking into account the interdependencies among options.

tanks and what replacement tanks to use, and it calculates the costs of implementing these decisions and operating the tank system. It supplies information on tank type and age, along with other operating factors, to the leak occurrence submodel for use in characterizing the potential for leaks. The tank operation submodel also considers how leak detection technology choices, as specified through the leak detection submodel, affect tank replacement decisions and system operating costs.

The leak occurrence submodel calculates the likelihood of a leak. This information is input to the leak detection submodel to help characterize the likelihood that a leak will be detected and also to the leak effects submodel to help calculate the expected leak duration. The duration and size of the leak are determined in the leak effects submodel and are used to estimate damages from the leak. Information on leak size is passed on to the remedial action submodel, which calculates cleanup costs. The cost submodel calculates the present value of all the cost streams—tank operation, tank replacement, damages from leaks, and expenses in cleaning up leaks.

The tank risk management model uses a decision tree to represent the sequence of tank testing and replacement decisions and the uncertainties in leak occurrence, detection, and costs (Figure 3). The time period for each cycle of decisions and uncertainties is typically one year, but longer or shorter time periods are possible.

In the figure the nodes with squares denote decisions, and their branches define alternative choices. The nodes with circles denote uncertainties, and their branches represent either discrete outcomes (e.g., leak detected or not detected) or the range of a continuous variable (e.g., cleanup costs).

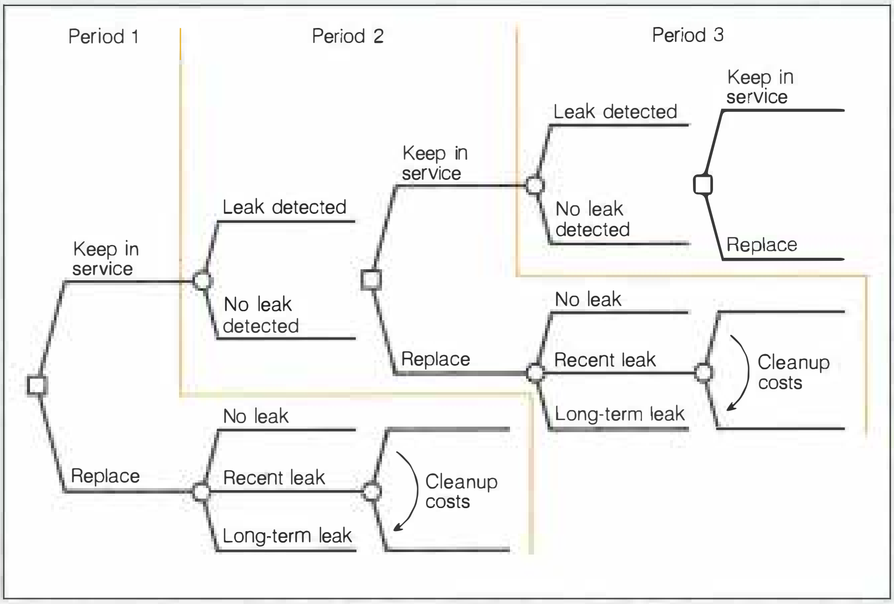
In the first period, the choice is whether to keep the tank in service. If the tank is replaced (lower branch), then the uncertainty about whether the tank is leaking and for how long is resolved, as are the uncertain costs of cleanup. If the decision is to keep the tank in service (upper branch), the model goes on to the second period.

In this period, first the uncertainty about whether a leak will be detected is resolved by considering the projected results of a set of leak detection tests. Then the decision about whether to replace the tank is made again. Leak detection technology is not perfect; it is possible to get indications of a leak when in fact there is none (a false positive) or indications that there is no leak when one does exist (a false negative). Thus the model considers the accuracy of the tests and reflects the fact that detecting a leak is not the same as having a leak.

If the second-period decision is to replace the tank, then the uncertainties about whether a leak has occurred and about the extent of cleanup costs will be resolved. Of course, the likelihood of leaks and of high cleanup costs is sensitive to the results of the leak detection testing. If the second-period decision is to keep the tank in service, then the model goes on to the third period and starts with the results of a second set of leak detection tests.

Although the model's primary output concerns the various components of total life-cycle costs, it provides additional results. Given a tank's age, the probability distribution on age to leak, the results of testing, and the accuracy of the test performed, the model estimates the probability that the tank is leaking and the probability distribution on the duration of the leak and determines whether the tank should be removed. If the tank is to be left in place, the model estimates how soon a leak is likely to be detected.

Figure 3 The decision tree used by the tank risk management model represents management decisions (squares) and uncertainty resolution (circles) over time. Flexible strategies that enable current-period decisions to reflect possible future responses to new information can greatly reduce the life-cycle costs of tank ownership.



Project status

The project was initiated in mid 1985 at the urging of utility industry advisers. To enable testing of the conceptual framework and to facilitate project review, a prototype model implementing the key features of the tank risk management model was developed.

For testing purposes, the prototype was made available to the Leaking Underground Storage Tank Committee of the Utility Solid Waste Activities Group (USWAG), which applied it to a review of alternative tank management policies concerning frequency of testing, replacement of existing tanks, and selection of new tanks. USWAG conducted the review in order to support its comments to EPA on these policies. (It should be noted that EPRI's role in this effort has been only to develop the model.)

Several thousand scenarios have been analyzed in the USWAG application. They covered various alternatives on tank type (including bare steel, cathodically protected steel, and fiberglass), tank age, likelihood of leakage, possible site risks, and strategies for testing, monitoring, and replacement.

The initial results of the analysis lead to an important insight. Leak costs, including the costs of eventual remedial action, are often a significant fraction of total life-cycle costs. For this reason the optimal policy is quite sensitive to the characteristics of the tank site. The major consideration is the potential cost of a leak at the site. This, in turn, determines the optimal amount of testing and monitoring, as well as the value of installing a more expensive and more leak-resistant tank. A corollary to this insight is that the use of an arbitrary fixed replacement age for tanks is a suboptimal strategy. Because it ignores site-specific characteristics, a policy that all tanks be replaced at 20 years of age, for example, can cost 50 to 100% more than the optimal, site-specific strategy.

The underground tank risk management system has been completed and is ready for application. Utilities interested in using the system should contact EPRI. *Project Manager: Victor Niemeyer*

R&D Status Report
ENERGY MANAGEMENT AND UTILIZATION DIVISION

Fritz Kalhammer, Vice President

INDUSTRIAL END-USE PLANNING METHODOLOGY

Uncertainties over future electricity consumption in the industrial sector highlight the need for improved forecasting. EPRI has initiated a major project to develop an industrial end-use planning methodology that will enable utilities to analyze the future of electricity sales at the service-area level (RP2217). Called INDEPTH, the methodology complements forecasting models already developed for the other customer classes: REEPS for the residential class, COMMEND for the commercial class, and AGEND for the agricultural class. The prime contractor for the project is Battelle, Columbus Division, with subcontract support from Synergic Resources Corp. and F. T. Sparrow & Associates.

The primary objective of the INDEPTH project is to design, develop, and demonstrate a methodology for forecasting industrial electricity use at the service-area level. The emphasis is on long-term forecasting (5–20 years) for the manufacturing industries—that is, those in standard industrial classifications (SICs) 20 through 39. A comprehensive forecasting system is being developed; it consists of a conceptual framework, mathematical equations, computer codes, and underlying data bases. It is designed for flexibility to reflect the diversity in the manufacturing sector and the different needs of forecasters in the utility industry.

Forecasts of electricity consumption in the industrial sector must take into account three major influences: the level of industrial output, the mix of that output, and the electricity use per unit of output (electricity intensity). The level of industrial output reflects macroeconomic factors, consumer confidence, and international competition. The mix of output is influenced by interindustry competition, the required factors of production, consumer preference, and international competition. Electricity intensity is affected by technology developments, production costs, and investment decisions. Figure 1 shows various factors affecting industrial electricity use and how the INDEPTH system addresses them.

After reviewing the industry's forecasting needs, the project researchers designed an end-use forecasting and planning system that incorporates a hierarchical menu of approaches. With the system the user can develop energy forecasts for the entire industrial sector, examine in detail those industries and industrial processes most important to the service area, and investigate those uses of electricity (such as motors or lighting) that are of

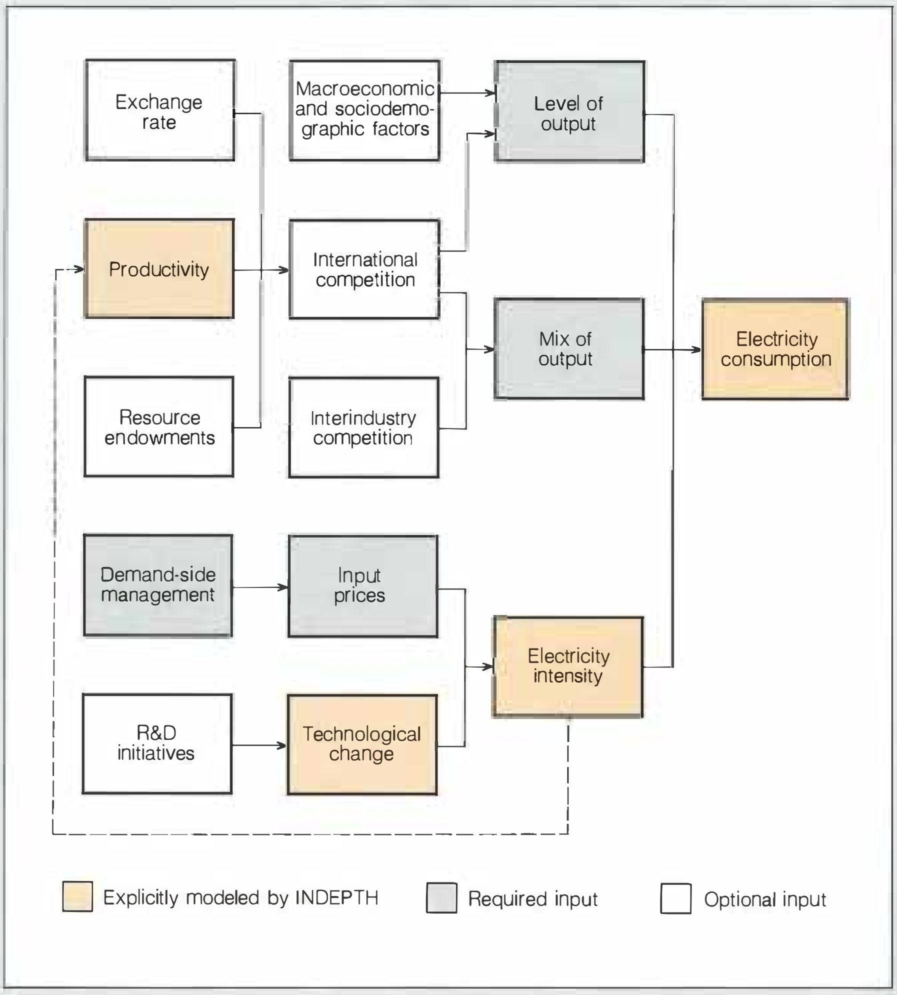


Figure 1 Several factors influence industrial electricity demand. This diagram shows the factors addressed by the INDEPTH system, a flexible forecasting tool being developed by EPRI. INDEPTH can assess the direct effect of product mix and technological changes on industrial electricity demand, as well as the indirect effect of electrotechnologies on industrial productivity.

interest in utility demand-side management programs. The system operates on three analytically distinct levels, each designed for specific applications: level 1, econometric models, useful primarily for forecasting; level 2, process models, useful for both forecasting and end-use assessments; and level 3, equipment models, useful for end-use assessments and demand-side management.

Econometric models

The primary goal for level 1 of the INDEPTH system was to develop econometric forecasting models for the 20 two-digit SIC industries covering the manufacturing sector. There are many econometric formulations that can be used to forecast electricity demand, including factor demand models, fuel share models, and production costing (cost minimization) models. After an extensive review of the literature and of the properties and assumptions of various models, a cost minimization specification was chosen. Models of this type are based on the principle that firms select inputs to the production process so as to maximize profits or, conversely, to minimize costs. Thus the models estimate how an industry's inputs change in response to changes in relative input prices and in output levels. The four major inputs considered—capital, labor, energy, and materials—give this specification its common name, KLEM. In this project energy was broken down into electricity and fossil fuel categories to yield a KLEFM configuration.

Data requirements include the prices of all inputs (capital, labor, electricity, natural gas, oil, coal, and materials), the expenditures on all of these inputs, and a measure of output. To meet these requirements, the researchers combined national and state data into a comprehensive data base. The national data (1958–1981) are from the U.S. Department of Commerce's Office of Business Analysis, and the state data (1967, 1971, 1974–1978) are from the Bureau of the Census's *Annual Survey of Manufactures* and *Census of Manufactures*. The data base will be available for calibration purposes and to EPRI members interested in exploring different model specifications.

This data base was used to estimate forecasting equations for the manufacturing industries. One result of special interest to utility planners is the change in electricity sales resulting from a change in electricity price. Table 1 shows the average electricity price elasticities that were estimated for the manufacturing industries.

Table 1
ESTIMATED ELECTRICITY PRICE ELASTICITIES

SIC Number	Industry	Price Elasticity
20	Food	−0.52
21	Tobacco	−0.52
22	Textiles	−0.58
23	Apparel	−0.60
24	Lumber	−0.44
25	Furniture	−0.42
26	Paper	−0.37
27	Printing	−0.85
28	Chemicals	−0.70
29	Petroleum	−0.53
30	Rubber	−0.31
31	Leather	−0.44
32	Stone, clay, and glass	−0.42
33	Primary metals	−0.56
34	Fabricated metals	−0.62
35	Machinery	−0.61
36	Electrical equipment	−0.28
37	Transportation	−0.55
38	Instruments	−0.72
39	Miscellaneous	−1.08

Process models

The level 2 models of the INDEPTH system—process models—estimate electricity consumption by focusing on the major electricity-consuming technologies and processes in a given industry. The key assumptions underlying a process model are that an industry has discrete production technologies or processes at its disposal to produce a given slate of outputs, and that the processes are selected on the basis of least cost. The level of output produced by the industry and, to a large extent, the mix of that output are exogenous (i.e., user-supplied) model inputs.

Process models are most appropriate for industries undergoing or anticipating major technological change as existing production technologies are challenged by new ones. Typically, the challenger technologies are newly developed, have a small market share, and offer the industry large potential savings through lower operating costs, higher efficiencies, or improved product quality. Process models simulate the competition between challenger and defender technologies to the extent that it is driven by production costs.

The structure of a process model is best described as a network of nodes and arcs; the nodes represent the material transformations that occur in an industry (and the process technologies involved), and the arcs represent the material flows. The level of the flows—and thus the utilization of the material transformation processes—is calculated such that the user-specified product demand is satisfied in the least-cost manner. Once the utilization of a process has been calculated, the electricity use follows, assuming that input requirements are proportional to utilization.

Process models simulate two different types of decisions faced by an industry: operating and investment decisions. Operating decisions focus on the utilization of an existing network; investment decisions focus on expanding the network's capacities to satisfy growth in product demand and to replace retired capacity.

The INDEPTH project is modeling 10 industries at the process level: textiles (SIC 2281), pulp and paper (2600), chlor-alkali (2812), petroleum (2911), glass (3220), cement (3241), iron and steel (3312), foundry (3321), metals fabrication (3440), and automotive stamping (3465). Nominal data bases describing these industries at the national level have been developed for all but the automotive stamping industry.

To illustrate the level of detail at which the industries are treated, Table 2 lists the technologies covered by the iron and steel model. Each process technology is characterized by capacity, operating cost, fuel costs, capital cost per unit of capacity, electricity requirements, efficiency, capacity utilization, and the age distribution of the existing capacity. Process models forecast electricity consumption indirectly by estimating first the stock of production technology in an industry and then the utilization of that stock. This leads to electricity projections not only for the industry but also for the major production processes within it.

Equipment models

The level 3 INDEPTH models—equipment models—are designed to simulate the purchase, retirement, and use of various types of energy-consuming (primarily electrical) equipment throughout the industrial sector. The INDEPTH equipment models are like the process models in that they are based on the principle of cost minimization; however, they differ in three key respects. First, the equipment models do not attempt to model all the processes used to produce a given product but instead concentrate on major equipment types present in most or all SICs. Second, because the equipment models are designed for a less detailed level of analysis than the process models, their structure has been developed at only the two-digit SIC level. Third, the equipment models are primarily allocation models. Energy consumption in the base year for a given industry is allocated to various equipment categories and the technologies within a given category. The mix of technologies changes over the forecast period as life-cycle costs for the technologies change.

The following equipment categories and technologies are covered in the INDEPTH equipment models.

- Motors: six size ranges; standard, high efficiency, and variable speed
- Lighting: incandescent, fluorescent, mercury vapor, high-intensity discharge, and sodium
- Chillers: two size categories; damper and variable-speed control; standard and absorption
- Dryers: high-temperature and low-temperature exhaust; microwave, infrared, and radio frequency
- Space heating: steam by-product, electric resistance, electric heat pump (standard and high efficiency), and dedicated steam boiler (coal, gas, oil, and electric)
- Furnaces: fuel fired, electric arc, induction, resistance, and plasma

As part of the INDEPTH project, a nominal data base was developed to verify the logic of the equipment model structure and to serve as a starting point for service-area-specific data collection. This data base contains allocations of electricity to various equipment categories and technologies, as well as performance, operating, and initial cost data for the various equipment types.

The output of an equipment model is energy consumption by equipment category and technology and by industry. As an example, Table 3 gives projections on changes in the composition of the lighting load for the total industrial sector from 1982 to 1990. (It should be noted that these figures are preliminary and are presented primarily for illustration.)

System application

Effective forecasting at the utility-service-area level requires a combination of techniques. The large data requirements of process models make them appropriate only for those industries that are of special interest to a utility because of their size, volatility of energy consumption, or potential for change in electricity requirements. For smaller industries with stable electricity consumption patterns, econometric models are much more appropriate. INDEPTH provides the forecaster with 20 econometric forecasting models covering all two-digit SIC industries in the manufacturing sector.

Whereas the econometric and process models emphasize forecasting, the INDEPTH equipment models examine how electricity use is affected by technological and market-share changes of key equipment types. Thus, once the econometric and process models have produced a baseline forecast, the equipment models can be used to estimate the net change expected to result from incentives or technological advances favoring one equipment type over another.

The emphasis of the INDEPTH project to date has been on designing the system (phase 1) and demonstrating the design's feasibility (phase 2). This work has entailed estimating and testing the econometric models, developing nominal data bases for the process and equipment models, and developing research computer codes for the three types of models. Phase 3 will focus on implementing and testing the entire system for several case study utilities, upgrading the computer codes, and transferring the system to utility forecasters and planners. Most of these activities are expected to be completed by the end of 1987. A report on the design of INDEPTH has been published (EPRI EA-4019), and an interim report describing the phase 2 results is forthcoming. *Project Manager: Ahmad Faruqui*

Table 2
PROCESS MODEL FOR THE IRON AND STEEL INDUSTRY

Process	Primary Technology	Secondary Technology
Iron and steel making	Electric arc furnace	Standard Hooded 30% direct reduced Hooded 30% direct reduced
	Integral basic oxygen furnace	Normal blast furnace High-temperature and -pressure blast furnace
	Integral open-hearth furnace	Normal blast furnace High-temperature and -pressure furnace
Casting and semifinishing	Alloy and stainless steel billets	Ingot casting, soaking Continuous casting
	Carbon steel billets	Ingot casting, soaking Continuous casting
Reheating	Pusher type Moving-beam type Induction type	
Final finishing	Blooms Slabs Billets	

Table 3
ELECTRICITY CONSUMPTION BY LIGHTING TYPE
(10^6 kWh)

Lighting Type	Year 1982	Year 1990
Incandescent	80	76
Standard fluorescent	2078	506
High-efficiency fluorescent	763	494
Mercury vapor	403	319
High-intensity discharge	499	323
High-pressure sodium	2657	3081
Low-pressure sodium	1449	3834
Total	7929	8633

R&D Status Report
NUCLEAR POWER DIVISION

John J. Taylor, Vice President

INSPECTION OF PWR CAST PIPES

The reliability of in-service inspections of main coolant piping in pressurized water reactors (PWRs) is being questioned by code and regulatory agencies. Round robin appraisals conducted by the Program for Inspection of Steel Components (PISC-II) and NRC—which are directed at evaluating the reliability of PWR inspections—have quantitatively demonstrated that PWR inspections are inadequate. This information, together with issues related to inspections for IGSCC in BWRs, has convinced code and regulatory bodies to institute changes that could drastically reshape in-service inspection practices. Because ultrasonic inspections of centrifugally cast stainless steel (CCSS) constitute a significant part of some PWR inspections, they too are of major concern in view of these contemplated regulatory changes.

Code Case N-335, "Rules for Ultrasonic Examination of Similar and Dissimilar Metal Piping Welds," illustrates the direction in which inspection practice will be moving. This document requires that inspection procedures, equipment, and personnel be effectively demonstrated in the presence of NRC representatives on fieldlike samples (e.g., flaw types and orientations, joint geometries, materials). On May 1, 1985, Georgia Power Co. was required to perform such a demonstration for the NRC Region II Office. Georgia Power successfully demonstrated its procedure for ultrasonically inspecting CCSS at its Vogtle facility.

Flaw detection in CCSS

Because of the way it is made, CCSS is composed primarily of two different grain structures: a coarse grain, or columnar, structure and a fine, equiaxed structure. A columnar structure demonstrates high attenuation and acoustic velocity irregularities, and it is a source of appreciable ultrasonic noise; as a result, it is difficult to examine ultrasonically. On the other hand, an equiaxed structure is relatively simple to inspect with ultrasound. The blend of these CCSS structures varies within a pipe and from pipe to pipe. Because the materials in the CCSS pipes at a given PWR plant are neither homogeneous nor isotropic, they are difficult to inspect.

EPRI is helping to solve the CCSS inspectability problem through its nozzle and pipe inspection project (RP2405), ultrasonic propagation studies (RP2687), and the establishment of the NDE Center (RP1570-2), as well as through its coordination with Westinghouse Electric Corp. (to avoid duplication of effort) and with various utilities.

As a major supplier of nuclear steam supply systems (NSSSs) for PWR plants, Westinghouse's interest, as EPRI's, is in the development of inspection techniques and procedures that will increase inspection reliability while complying with the requirements of regulatory agencies. Because these inspection problems are licensing issues, it is of utmost importance to the utilities that solutions be found as soon as possible.

EPRI's approach is to follow a sequence of diagnostic procedures and then make evaluations. Data and an accumulation of knowledge are key factors in the diagnostic procedures, as are the diagnostic tools. Through the NDE Center, Westinghouse and EPRI are gathering samples of CCSS and then manufacturing other samples that incorporate a variety of the flaw types usually found in PWR main coolant piping. When possible, digital recordings of ultrasonic waveforms taken from these samples are being made and correlated with metallographic analyses of the samples.

Westinghouse has assembled samples that include CCSS pipes obtained from their major vendors, piping configurations found in PWR plants, and pipes manufactured at different times. EPRI-developed instruments, such as IntraSpect (T101-4) and TestPro (RP2405-14), are being used in the digital recording of ultrasonic images and ultrasonic waveforms.

These data are used in the ultrasonic propagation studies to develop mathematical and physical models of the interactions of ultrasonic energy with CCSS and with any flaws the steel may contain. Two techniques are being used. Ames Laboratories (Iowa State University) and Northwestern University are cooperating in an effort to develop a sound-scattering theory (model) for CCSS (RP2687-01). This will be an analytic model, that is, one that consists of a collection of mathematical formulas that describe CCSS sound paths and reflection characteristics. The work also covers models of current inspection procedures.

Colorado State University (RP2687-03) and Drexel University (RP2405-18) are generating numerical models of ultrasonic-CCSS interactions. Numerical models are algorithms that are run on a computer to simulate the trajectories of sound through various material configurations. The results of these simulations are used by those developing analytic models, as well as to provide model verification through comparisons with experimental results. The most important aspects of modeling are accurate information about the physics involved; evaluations of the weaknesses of current techniques and of the possible strengths of new techniques; and development of a framework within which the effectiveness of inspection techniques and procedures can be determined.

One of the richest sources of relevant inspection data is the piping in operating PWR plants. In June 1985, a group of engineers from the NDE Center and Amdata (developers of IntraSpect) spent 10 days collecting ultrasonic data from CCSS coolant piping at Georgia Power's Vogtle facility. These data are being analyzed and are expected to yield valuable information about the possibilities of using advanced ultrasonics for PWR inspections. The piping systems from which data were obtained had previously been inspected entirely by manual methods. In this procedure, an inspector scans a pipe with a hand-held sound transducer and observes the echoes on an oscilloscopelike ultrasonic instrument. Echoes exceeding certain amplitude criteria indicate sites of possible defects. These indications are recorded and later examined by an expert in ultrasonic analysis to determine whether flaws actually exist.

Advanced ultrasonic inspection systems incorporate mechanical scanners and provide for the digital recording of signals. Images can be generated from the data, the data can be replayed as often as desired, and the data can be made accessible to a number of experts simultaneously. Laboratory and round-robin studies show that these advanced systems are more reliable and exhibit better fidelity than manually operated equipment. The signal processing options offered by the advanced systems can greatly enhance signal-to-noise characteristics of CCSS.

New diagnostics

Work is in progress to combine two different modes of advanced ultrasonics into a single diagnostic and analytic tool for inspecting PWR piping: imaging and pattern recognition. General Electric Co. now uses the ultrasonic imaging system UltraImage III for making BWR inspections. UltraImage effectively images CCSS, and the images are useful for discerning spatial relationships between reflectors and echoes. Images cannot, however, identify a reflector in a specific sense. Reflector identification, or characterization, is more readily accomplished through feature-based pattern recognition techniques.

Features are parameters available from ultrasonic waveforms that can be correlated with the type of reflector by which they were produced. For example, feature-based systems can differentiate between cracks and weld roots. Pattern recognition uses features in mathematical algorithms, which are weighted combinations of features. The output of these algorithms is a number that is used to categorize a reflector as, for example, coming from a crack, a counterbore, or a region where there is a lack of fusion.

Combining image-based and feature-based systems should produce the most effective diagnostic-analytic tool available for inspecting CCSS pipes (T301-20).

It is expected that these advanced ultrasonic inspection techniques will afford significant advantages to the utilities and their vendors, as well as to the regulatory agencies. Details of this work on CCSS inspections will be presented in a report scheduled for publication in mid 1987. *Project Manager: Michael J. Avioli, Jr.*

HYDROGEN WATER CHEMISTRY FOR BWRs

Since 1974 intergranular stress corrosion cracking (IGSCC) of stainless steel piping in boiling water reactors (BWRs) has been a costly problem for BWR operators. Extensive studies of IGSCC, particularly as it affects the sensitized material adjacent to girth welds, have produced several remedies that rely on improved materials and reduced local stresses (NP-3684-SR). In a different approach, laboratory studies of the effects of BWR water chemistry on IGSCC led to the development of a technique—hydrogen water chemistry (HWC)—that retards cracking by adding hydrogen to the reactor feedwater. Long-term verification tests of HWC have been in progress since 1983. NP-4592-SR is a more comprehensive review of the HWC development program in the United States.

Laboratory test results (NP-2879-SR) suggest that BWR pipe cracking occurs mainly during power operation when the reactor water is at about 280°C (536°F) and contains small quantities of dissolved gases and other impurities (NP-3663). As illustrated in Figure 1, test data for 280°C water show that IGSCC is suppressed at stainless steel corrosion potentials below a protection potential range. The value of the protection potential decreases with increasing concentrations of such corrosive anionic impurities as Cl^- and SO_4^{--}, that is, with increasing conductivity. For the conductivity levels consistently achievable in BWR reactor water ($\leq$0.3 μS/cm), the protection potential is thought to be about −230 mV on the standard hydrogen electrode (SHE) scale.

To suppress pipe cracking in a BWR, the corrosion potential must be reduced from the usual values of 50 ± 100 mV (SHE) to $\leq$230 mV (SHE) while the reactor water conductivity is kept at $\leq$0.3 μS/cm. In-reactor experiments cofunded by EPRI and DOE at Commonwealth Edison Co.'s Dresden-2 during 1982 showed that adding ~1.5 ppm hydrogen to the feedwater lowered the stainless steel corrosion potential into the required range by reducing the concentration of oxygen dissolved in the recirculation water from 100 ppb to less than 20 ppb. Tests on sensitized stainless steel specimens confirmed that IGSCC was suppressed at Dresden-2 when the dissolved oxygen in the recirculation water was kept at $\leq$20 ppb and the conductivity at $\leq$0.3 μS/cm. Because of these results, EPRI sponsored a long-term HWC verification project at Dresden-2 in April 1983 (RP1930).

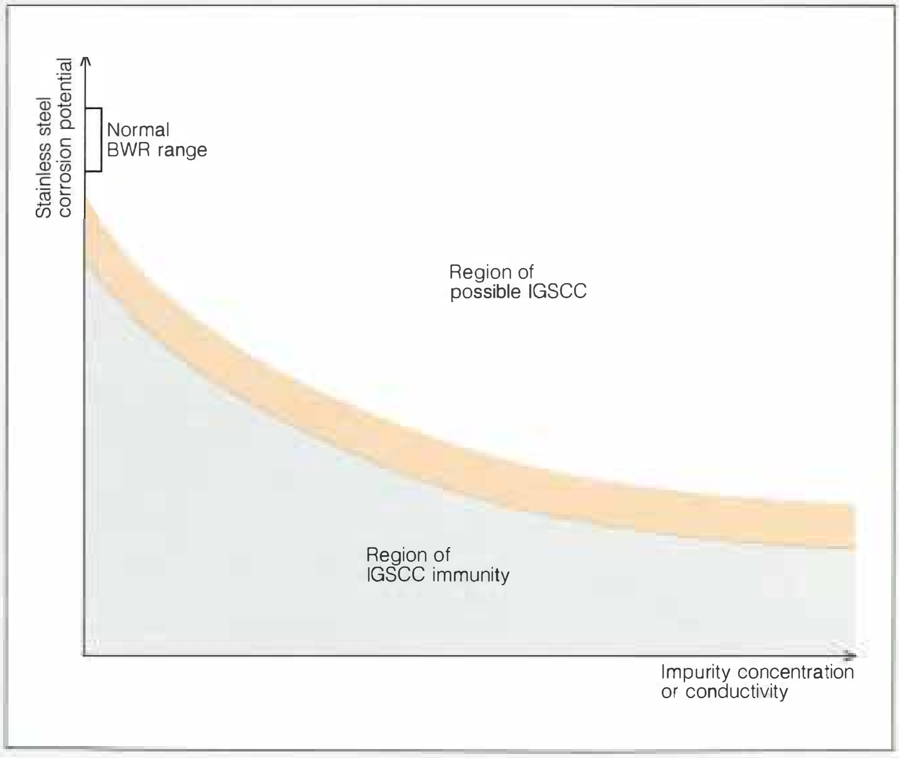


Figure 1 The relationship between ionic impurity concentration (conductivity) and corrosion potential in terms of IGSCC. The figure is based on extensive laboratory data for sensitized austenitic steels in 280°C (536°F) water. By operating with combinations of corrosion potential and conductivity that fall below the range of the protection potentials (color band), plants can effectively prevent IGSCC (gray area).

HWC verification at Dresden-2

The HWC project in progress at Dresden-2 includes water chemistry monitoring, in-plant testing of structural materials, fuel-performance surveillance, and assessment of the effects of HWC on plant operations. By the end of 1985 about 24 months of continuous operation on HWC had been completed (the planned program duration is 36 to 54 months—two or three 18-month fuel cycles).

In accordance with the results of the 1982 feasibility test, the HWC specification for the long-term project at Dresden-2 was as follows: conductivity, $\leq 0.3\ \mu S/cm$; dissolved oxygen, ≤ 20 ppb; and feedwater hydrogen concentration, ~ 1.5 ppm. The hydrogen injection system was designed to maintain the specified feedwater hydrogen concentration (ppm) whenever the plant was operating above 25% of rated power.

From April 1983 to the end of 1985, Dresden-2 operated within the specified ranges of conductivity and dissolved-oxygen concentration for about 80% of the time that plant output was above 25% of rated power. Almost all the out-of-specification operation was attributable to outages of the hydrogen injection system, which resulted in dissolved oxygen concentrations that rose to values between 20 and 200 ppb. About 70% of the cumulative operating time at oxygen concentrations above 20 ppb was made up of many brief periods (≤ 10 hours), and tests indicate that such brief periods of operation with higher levels of dissolved oxygen do not cause IGSCC. This suggests that from April 1983 through December 1985, the stainless steel piping at Dresden-2 was exposed to water conductivities and corrosion potentials that were in the IGSCC-immune range more than 90% of the time that plant output was above 25% of rated power (NP-4470M).

The outages of the hydrogen injection system resulted from a variety of causes, including shutdowns for maintenance of the system itself, for maintenance in areas of the plant where there are high levels of gamma radiation during hydrogen injection, and for extinguishing fires in the off-gas system. (The off-gas fires were not directly attributable to HWC, and none occurred during the most recent six months of operation.) The main adverse effect of HWC on plant operations is the fivefold increase in steam-line radiation levels that accompanies operation in the IGSCC-immune regime at Dresden-2. However, by carefully controlling the effects of the additional radiation (including the deliberate shutdowns of the injection system), Commonwealth Edison has held increases in plant personnel exposures to less than 1% (EPRI NP-4011).

In addition to monitoring conductivity and oxygen concentration, the HWC verification program provides for ion chromatographic studies, measurements of various metals and isotopes in the feedwater and reactor water, and radiation buildup studies. Although some measurable HWC-induced effects have been observed, they have not been major (NP-4470M).

Slow strain-rate SCC tests were conducted in Dresden-2 recirculation water on sensitized type-304 stainless steel and on several carbon and low-alloy steels. The results of tests on stainless steel confirm that IGSCC is suppressed when the plant operates within the HWC specification and indicate that short-term excursions to out-of-specification oxygen levels can be tolerated. On the basis of limited data, an exposure period of more than 10 hours at higher oxygen levels is needed to cause detectable IGSCC damage. All the carbon and low-alloy steel specimens tested to date have failed in a completely ductile manner with no indication of the transgranular SCC sometimes observed under normal BWR water chemistry conditions (NP-4592-SR).

Longer-term crack growth tests have also been conducted on sensitized type-304 stainless steel under RP1903-1. No significant crack extension occurred during 2000 hours of testing that included two reactor scrams and several interruptions of hydrogen injection. This observation supports the conclusion that no significant IGSCC has occurred in Dresden-2 recirculation piping since the beginning of the HWC verification program. The results of in-service pipe inspections are consistent with this conclusion.

The materials testing also includes periodic measurements of stainless steel corrosion potential. The main purpose is to verify that the specified dissolved oxygen concentration of ≤ 20 ppb is effective in maintaining the corrosion potential below the protection potential. The measurements show that whenever the oxygen content is less than 20 ppb, the stainless steel corrosion potential is less than -230 mV (SHE), which is the presumed protection potential.

The HWC verification program includes an extensive investigation of the performance of fuel cladding and other Zircaloy core components (RP1930-10). Areas of emphasis include Zircaloy corrosion and hydriding, as well as crud buildup on the fuel. These subjects are being investigated by using a combination of nondestructive poolside examinations and destructive hot cell analyses. To date, fueled and nonfueled components from three bundles have been examined: one bundle was exposed to normal water chemistry for three cycles and was discharged before the HWC verification program began; the second bundle was exposed to normal water chemistry for two cycles and to HWC for its third cycle; and the third bundle (a specially precharacterized lead test assembly) was exposed to HWC for only one cycle of HWC operation.

The results of the corrosion and hydriding studies indicate little or no effect of HWC. There were measurable effects of HWC on crud buildup, but overall the crud characteristics were still in the range considered normal for BWRs and there were no indications of any adverse effect on fuel performance. (A more detailed account of this work is given in the April/May 1986 *EPRI Journal*, p. 54.)

HWC implementation at other plants

As part of the overall HWC development effort, three activities have been completed that were intended to facilitate the implementation of HWC at other U.S. plants: assessing the effects of HWC-induced increases in radiation, analyzing the results of short-term HWC tests, and developing guidelines for permanent HWC installations.

Injecting hydrogen into the reactor feedwater increases the gamma radiation field in and around the plant during power operation because more of the gamma-emitting nitrogen-16 isotope formed in the core partitions into the steam under HWC than under normal water chemistry conditions. At Dresden-2 this results in a fivefold increase in steam line radiation levels. Although this effect has been manageable at Dresden, it was thought that differences in plant designs and site configurations could make it more significant at other plants. Accordingly, the effect of the anticipated field increases on the radiation dose to three groups—the general public, plant personnel in restricted areas of the site, and plant personnel in unrestricted areas—was assessed for 29 BWR power plant sites in the United States.

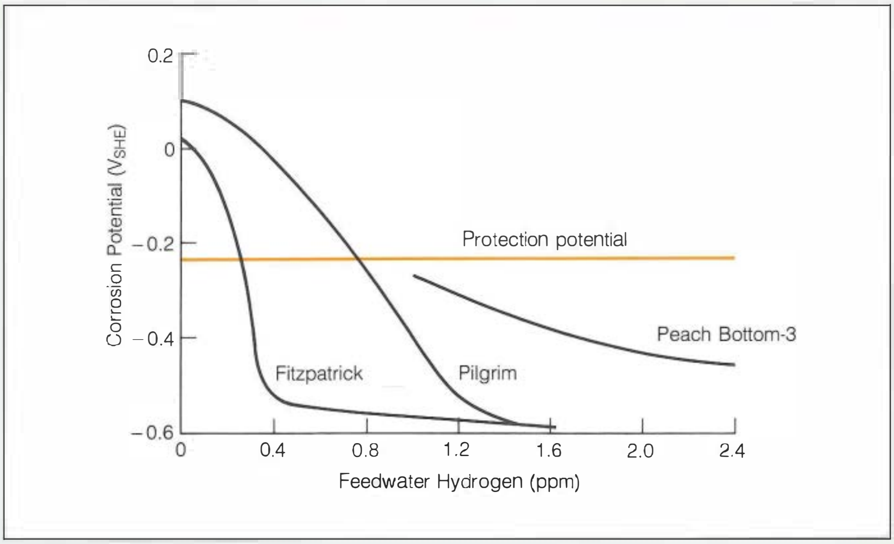
It was concluded (1) that at nine sites, radiation dose rates would be well below the regulatory limits for the three groups considered; (2) that at five sites, dose rates would exceed 50% of the regulatory limit for at least one group; and (3) that at the remaining five sites, dose rates would exceed the regulatory limit for one group and approach it for a second group. Mitigating actions (mainly additional turbine-deck shielding) would be necessary at the five item-3 sites if HWC is implemented and might also be desirable at the five item-2 sites (NP-4416).

Short-term HWC tests were successfully conducted at the Peach Bottom-3, Pilgrim, and Fitzpatrick BWRs during 1985. These so-called minitests were performed by the utilities to provide plant-specific data about the ways in which injecting hydrogen into the feedwater affected the oxidizing power of the recirculation system water, the oxygen and hydrogen concentrations in the reactor coolant and main steam systems, and the radiation fields in and around the plant during power operation. The data obtained show that the response of BWRs to hydrogen injection varies significantly from plant to plant (NP-4592-SR). For example, at the same feedwater hydrogen concentration of 0.7 ppm and at full power operation, the dissolved oxygen concentration in the recirculation system was <1 ppb at Fitzpatrick, 4 ppb at Pilgrim, and 30 ppb at Peach Bottom-3. However, at all three plants it was possible to define a practical rate of hydrogen injection that depressed the corrosion potential of stainless steel in the recirculation system to values less than the IGSCC protection potential (Figure 2). That is, HWC is potentially an effective method of protecting stainless steel piping from IGSCC at all three plants.

Of special interest among the minitest results was the observation at Fitzpatrick that the recirculation system could be protected against IGSCC under conditions that produced only a 20% increase in the steam line radiation field. This observation, which was verified by conducting slow strain-rate tests on sensitized stainless steel specimens to confirm the absence of IGSCC, is in sharp contrast to the fivefold field increase that accompanied IGSCC suppression at Dresden-2. The Fitzpatrick result indicates that a large increase in radiation fields in and around a nuclear plant is not an inevitable consequence of the use of HWC to suppress IGSCC. Moreover, it highlights the need to develop an improved quantitative understanding of the way in which hydrogen injection affects water chemistry in the core and coolant circuits of an operating BWR. Pending the development and verification of the required chemical models, a minitest would be a worthwhile investment for any utility considering the use of HWC.

An industry committee organized by EPRI on behalf of the BWR Owners Group for IGSCC Research (BWROG-II) recently completed a document that sets forth general guidelines for designing, installing, and operating HWC systems (NP-4500-SR-LD). This document, which is currently being reviewed by NRC, identifies those aspects of HWC implementation that are likely to require prior review and approval by NRC and provides suggested approaches and technical bases for the required safety analyses. It also identifies aspects of HWC implementation that can proceed under licensee responsibility, and it reviews and references pertinent "good practices" documents. When the NRC staff review is complete and their comments have been addressed and incorporated, the revised document will be issued to all BWR utilities and will provide a uniform basis for future licensing activities related to HWC implementation.

Figure 2 The effects of hydrogen injection vary from plant to plant. Nevertheless, at these three U.S. plants it was possible to drop corrosion potentials below the protection potential (color line) by raising the feedwater hydrogen concentration above a certain, plant-specific level. Above this point, no IGSCC is expected.



HWC prospects

Results obtained thus far in the HWC program support the conclusion that the technique of injecting hydrogen into BWR feedwater to reduce the corrosion potential of stainless steel in the reactor water, together with careful control of plant water quality, can be developed into an effective remedy for the pipe cracking problem in BWRs. Two years of experience at Dresden-2 indicate that the implementation of HWC in an operating power plant is feasible and that long-term protection against IGSCC can be provided.

The only significant adverse effect of HWC found at Dresden-2—a substantial increase in the operating radiation fields—has proved to be manageable. Concerns about potential effects of HWC on fuel performance have been considerably reduced by the results of fuel examinations after one cycle of HWC operation; however, surveillance for an additional two cycles will be necessary to provide final confirmation of satisfactory fuel performance in the presence of HWC. Another area requiring further work is the plant-to-plant variability observed in the minitests. A better understanding of this variability is necessary to verify that a plant-specific HWC specification based on a minitest lasting a few days will in fact provide protection against IGSCC throughout the subsequent life of the plant. In the meantime, periodic empirical demonstrations of HWC effectiveness are recommended for plants adopting hydrogen water chemistry. *EPRI Project Managers: Robin Jones, Christopher Wood, Albert Machiels, J. Lawrence Nelson, Daniel Cubicciotti, and Warren Bilanin*

New Contracts

Project	Funding/ Duration	Contractor/EPRI Project Manager
Coal Combustion Systems		
Cycling Studies at Niagara Mohawk Power Corp.'s Oswego-5 (RP1184-17)	$200,000 26 months	Niagara Mohawk Power Corp./*F. Wong*
Filters for High-Temperature, High-Pressure Gases (RP1336-7)	$518,000 22 months	Technical University of Aachen, West Germany/ *O. Tassicker*
Electrical Systems		
PCB Residue in Askarel Transformer Carcasses (RP2028-19)	$148,400 5 months	General Electric Co./ *G. Addis*
Power Plant Auxiliary System Improvements (RP2626-1)	$239,000 9 months	General Electric Co./ *J. Stein*
Energy Analysis and Environment		
Reacidification of Previously Limed Lakes (RP2337-2)	$126,600 27 months	Swedish Environmental Research Institute/ *D. Porcella*
Unbundling Service: Priority Service Methods (RP2801-1)	$100,000 9 months	Pricing Strategy Associates/*H. Chao*
Energy Management and Utilization		
Market Potential and Commercialization Strategy for Lead-Acid Battery Systems for Load Management Applications (RP1084-21)	$57,600 11 months	Battelle, Columbus Laboratories/*D. Rigney*
Small Cogeneration Technology Directory and Project Support (RP1276-27)	$115,300 12 months	Science Applications International Corp./*D. Hu*
Development of a Continuous Electric Kiln to Sinter Alumina Parts (RP2730-3)	$107,000 9 months	Harrop Industries/*A. Karp*
Nuclear Power		
Development of Guidelines for Makeup Water Treatment Plant Design and Operation (RPS306-19)	$66,000 9 months	Sargent & Lundy Engineers/*S. Hobart*
Concentration Factors and Mechanisms of Hideout and Return of Salts in Heated Crevices, Using Radioactive Sodium as a Tracer (RPS311-4)	$233,000 2 months	Commissariat à L'Energie Atomique/*C. Shoemaker*
Model: Effect of Sulfur Species on Crack Growth Rates (RP1325-12)	$316,200 24 months	Framatome/*J. Gilman*
Support for HDR Seismic Experiments (RP1444-7)	$77,800 8 months	Robert L. Cloud Associates, Inc./*A. Singh*
Snubber Elimination, Using Energy Absorber Restraints (RP1586-2)	$103,100 3 months	Bechtel Group, Inc./ *H. Tang*
Modular HTGR Water Ingress Analysis (RP2079-13)	$84,600 5 months	General Electric Co./ *R. Hayman*
Containment Isolation Valve Improvements (RP2233-4)	$354,500 25 months	Babcock & Wilcox Co./ *B. Brooks*
Simplified Nonlinear Dynamic Piping Analysis Methodology Development (RP2350-2)	$222,200 13 months	Rockwell International Corp./ *H. Tang*
Characterization of Reactor Vessel Mechanical Properties (RP2455-11)	$80,000 22 months	University of California at Santa Barbara/ *T. Griesbach*
Long-Term Blowdown in Containment Experiment at HDR Facility (RP2600-11)	$34,800 8 months	Kernforschungzentrum Karlsruhe GmbH/ *B. Sehgal*
LMFBR Technical Integration Studies (RP2658-4)	$310,000 12 months	Rockwell International Corp./*C. Gibbs*
Signal Processing Development for Steam Generator Tube Inspection (RP2673-2)	$162,100 18 months	Combustion Engineering, Inc./*M. Avioli*
Advanced Ultrasonic Techniques for Steam Generator Tube In-Service Inspection (RP2673-5)	$50,900 9 months	Illinois Institute of Technology/*M. Avioli*
Implementation of Critical Location Evaluations for Generic Fatigue Damage Management (RP2688-5)	$75,000 9 months	Combustion Engineering, Inc./*T. Griesbach*
Reevaluation of Nuclear Plant Seismic Margin (RP2722-2)	$215,300 19 months	Pickard, Lowe and Garrick, Inc./*R. Kassawara*
Assessment of Nondestructive Examination of Steam Generator Sludge (RP2755-3)	$87,400 7 months	Westinghouse Electric Corp./*C. Williams*
Assessment of Nondestructive Examination of Steam Generator Sludge (RP2755-5)	$42,800 6 months	Combustion Engineering, Inc./*C. Williams*
Assessment of Steam Generator Sludge Lancing (RP2755-7)	$76,000 6 months	Anco Engineers, Inc./ *C. Williams*
Assessment of Steam Generator Sludge Lancing (RP2755-8)	$40,700 10 months	Babcock & Wilcox Co./ *C. Williams*
Assessment of Steam Generator Sludge Lancing (RP2755-10)	$90,000 5 months	Foster-Miller, Inc./ *C. Williams*
Detailed Analysis of BWR ATWS Severe Accidents (RP2761-1)	$240,800 8 months	General Electric Co./ *B. Sehgal*
Aerosol Formation and Transport Studies (RP2802-3)	$249,800 10 months	Argonne National Laboratory/*R. Ritzman*
Support to the LACE Aerosol Behavior Program (RP2802-4)	$103,700 14 months	Intermountain Technologies, Inc./*F. Rahn*
Ultrasonic Instrumentation of Nodular Cast Iron (RP2813-2)	$59,600 10 months	Amdata, Inc./*S. Liu*
Stress Corrosion Crack Initiation by Electrochemical Countermeasures (RP8002-1)	$180,700 36 months	AERE Harwell/ *D. Cubicciotti*

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

Use of Lignite in Texaco-Gasification-Based Combined-Cycle Power Plants
AP-4509 Final Report (RP2221-1); $40.00
Contractor: Energy Conversion Systems, Inc.
EPRI Project Manager: M. Epstein

Cost Estimates for Vertical-Axis Wind Turbines
AP-4528 Final Report (RP1989-2); $40.00
Contractor: Bechtel Group, Inc.
EPRI Project Managers: S. Kohan, M. Gluckman

Steam Pretreatment of Subbituminous Coal
AP-4531 Final Report (RP2147-9); $25.00
Contractor: Purdue University
EPRI Project Manager: L. Atherton

Wyodak Coal: Composition, Reactions, and Products
AP-4536 Final Report (RP2655-3); $25.00
Contractor: University of North Dakota Energy Research Center
EPRI Project Manager: L. Atherton

Development of High-Chromium Ferritic Clad Heat Exchanger Tubing
AP-4579 Interim Report (RP2048-7); $25.00
Contractor: AMAX Materials Research Center
EPRI Project Manager: W. Bakker

UNIRAM Analyses of Power System Maintenance Strategies
AP-4580 Final Report (RP1461-1); $32.50
Contractor: Arinc Research Corp.
EPRI Project Manager: J. Weiss

Alkaline Hydrolysis Transformation of Coal
AP-4585 Final Report (RP2655-2); $25.00
Contractor: Dynatech R/D Co.
EPRI Project Manager: L. Atherton

Wind Power Instrumentation Directory
AP-4586 Final Report (RP1996-2); $25.00
Contractor: R. Lynette & Associates, Inc.
EPRI Project Manager: F. Goodman

Corrosion of Refractories in a Synthetic Coal Slag
AP-4589 Final Report (RP2048-4); $25.00
Contractor: Argonne National Laboratory
EPRI Project Manager: W. Bakker

Testing Requirements for Variable-Speed Generating Technology for Wind Turbine Applications
AP-4590 Final Report (RP1996-22); $25.00
Contractor: Electrotek Concepts, Inc.
EPRI Project Manager: F. Goodman

COAL COMBUSTION SYSTEMS

Hydrothermal Performance of Vertically Stratified Cooling Ponds
CS-4320 Final Report (RP2385-1); $32.50
Contractor: Massachusetts Institute of Technology
EPRI Project Manager: J. Bartz

Wet-Dry Cooling Demonstration: Test Results
CS-4321 Interim Report (RP422-3); $32.50
Contractor: Battelle, Pacific Northwest Laboratories
EPRI Project Manager: J. Bartz

Performance of a Capacitive Cooling System for Dry Cooling
CS-4322 Final Report (RP422-12); $25.00
Contractor: CBI Industries, Inc.
EPRI Project Manager: J. Bartz

Selective Catalytic Reduction for Coal-Fired Power Plants: Pilot Plant Results
CS-4386 Final Report (RP1256); $47.50
Contractor: KVB, Inc.
EPRI Project Manager: E. Cichanowicz

Coal Cleaning Test Facility Campaign Report No. 3: Stockton-Lewiston Seam Coal
CS-4433 Interim Report (RP1400-6, -11); $40.00
Contractors: Raymond Kaiser Engineers, Inc.; Science Applications International Corp.
EPRI Project Managers: C. Harrison, J. Hervol

Microcomputer-Based Flow and Mass Balances for Power Plant Water Management
CS-4482 Final Report (RP2114-2); Vol. 1, $32.50; Vol. 2, $40.00
Contractor: CH2M Hill, Inc.
EPRI Project Manager: W. Micheletti

Titanium L−1 Steam Turbine Blade Retrofit
CS-4515 Final Report (RP1264-1); $150.00
Contractor: Westinghouse Electric Corp.
EPRI Project Manager: R. Jaffee

Advanced Rotor Forgings for High-Temperature Steam Turbines
CS-4516 Final Report (RP1343-1); Vol. 1, $150.00; Vol. 2, $150.00
Contractor: Westinghouse Electric Corp.
EPRI Project Manager: R. Jaffee

Mechanisms of Failure of Coatings Used in Flue Gas Desulfurization Systems
CS-4546 Interim Report (RP1871-5); $32.50
Contractor: Lehigh University
EPRI Project Manager: B. Syrett

Coal Cleaning Test Facility: 1986 Plan
CS-4547 Interim Report (RP1400-6, -11); $40.00
Contractors: Raymond Kaiser Engineers, Inc.; Science Applications International Corp.
EPRI Project Managers: C. Harrison, J. Hervol

Heat-Rate Improvement Guidelines for Existing Fossil [Fuel] Plants
CS-4554 Final Report (RP1403-3); $500
Contractor: Delian Corp.
EPRI Project Manager: F. Wong

Effects of Sulfide, Sand, Temperature, and Cathodic Protection on Corrosion of Condensers
CS-4562 Interim Report (RP1689-3); $32.50
Contractor: Ocean City Research Corp.
EPRI Project Manager: B. Syrett

Interim Consensus Guidelines on Fossil [Fuel] Plant Cycle Chemistry
CS-4629 Final Report (RP2712-1); $1000
Contractor: Sargent & Lundy
EPRI Project Manager: B. Dooley

ELECTRICAL SYSTEMS

Electrification Problems Resulting From Liquid Dielectric Flow
EL-4501 Final Report (RP1536-7); $32.50
Contractor: Massachusetts Institute of Technology
EPRI Project Manager: H. Mehta

TLWorkstation Code: Version 1.0
EL-4540-CCM Computer Code Manual (RP561, RP1352, RP2016-3); Vols. 12–15, $25.00 each
EPRI Project Manager: R. Kennon

Large-Deviation Approximation to Computation of Generating-System Reliability and Production Costs
EL-4567 Final Report (RP1529-4); $25.00
Contractor: University of Pittsburgh
EPRI Project Managers: N. Balu, M. Pereira

ENERGY ANALYSIS AND ENVIRONMENT

The Value of Service Reliability to Consumers
EA-4494 Proceedings (RP1104-6); $55.00
Contractor: Criterion, Inc.
EPRI Project Managers: R. Wyzga, P. Ricci

MYGRT: An IBM Personal Computer Code for Simulating Solute Migration in Groundwater—User's Manual
EA-4543-CCM Computer Code Manual (RP2485-1); $25.00
Contractor: Tetra Tech, Inc.
EPRI Project Managers: I. Murarka, D. McIntosh

Remote Sensing to Detect Ecological Impacts Associated With Acid Deposition
EA-4607 Final Report (RP2380-5); $25.00
Contractor: Battelle, Pacific Northwest Laboratories
EPRI Project Manager: J. Mattice

ENERGY MANAGEMENT AND UTILIZATION

Financial and Strategic Planning Benefits of Fuel Cell Power Plants
EM-4511 Final Report (RP1677-12); Vol. 1, $32.50; Vol. 2, $25.00
Contractor: Temple, Barker & Sloane, Inc.
EPRI Project Manager: D. Rigney

EPRI Simplified Program for Residential Energy (ESPRE): Review of Energy Analysis Methods and Model Development
EM-4523 Final Report (RP1775-1); Vol. 1, $25.00
Contractor: Arthur D. Little, Inc.
EPRI Project Managers: S. Braithwait, E. Beardsworth

Residential End-Use Load-Shape Estimation: Methodology and Results of Statistical Disaggregation From Whole-House Metered Loads
EM-4525 Final Report (RP2145-1); Vol. 1, $32.50
Contractor: Scientific Systems, Inc.
EPRI Project Manager: S. Braithwait

Electron Beam Processing of Metals: State-of-the-Art Assessment
EM-4526 Final Report (RP2478-1); $25.00
Contractor: Battelle, Columbus Division
EPRI Project Manager: L. Harry

Energy Management Pilot Program for Industry
EM-4549 Final Report (RP1275-1); $25.00
Contractor: United Technologies Research Center
EPRI Project Manager: D. Hu

Cogeneration for Industrial and Mixed-Use Parks
EM-4576 Final Report (RP1276-19); Vol. 1, $32.50; Vol. 2, $32.50; Vol. 3, $25.00
Contractor: Impell Corp.
EPRI Project Manager: D. Hu

1985 Survey of Utility Residential End-Use Projects
EM-4578 Final Report (RP1940-20); $60.00
Contractor: Plexus Research, Inc.
EPRI Project Manager: V. Rabl

Rock Cavern Linings for Compressed-Air Energy Storage
EM-4584 Final Report (RP1791-12); $32.50
Contractors: Cementation Company of America, Inc.; Acres American, Inc.
EPRI Project Managers: B. Mehta, R. Schainker

NUCLEAR POWER

Nondestructive Evaluation Program: Progress in 1985
NP-4315-SR Special Report; $55.00
EPRI Project Manager: M. Behravesh

Improved Reliability for Analog Instrument and Control Systems
NP-4483 Final Report (RP2409-2); Vol. 1, $25.00; Vol. 2, $40.00
Contractor: Science Applications International Corp.
EPRI Project Manager: G. Shugars

EPRI Database for Environmentally Assisted Cracking (EDEAC)
NP-4485 Interim Report (RP2006-2); $40.00
Contractor: Battelle, Columbus Division
EPRI Project Manager: J. Gilman

Resin and Ionics Leakage From Condensate Polishers With and Without Inert Resin
NP-4521 Final Report (RPS306-16); $25.00
Contractor: Babcock & Wilcox Co.
EPRI Project Managers: S. Hobart, C. Welty

Oxidation of Spent Fuel at Between 250 and 360°C
NP-4524 Topical Report (RP2062-10); $32.50
Contractor: Westinghouse Hanford Co.
EPRI Project Manager: R. Lambert

Effects of Zircaloy Oxidation and Steam Dissociation on PWR Core Heat-up Under Conditions Simulating Uncovered Fuel Rods
NP-4529 Interim Report (RP1760-3); $25.00
Contractor: Purdue University
EPRI Project Manager: J. Kim

Critical Flow Through Small Pipe Breaks
NP-4532 Final Report (RP2299-2); $32.50
Contractor: EG&G Idaho, Inc.
EPRI Project Manager: G. Srikantiah

Nonlinear Dynamic Analysis of Pipe Whip Tests
NP-4535 Final Report (RP1324-7); $32.50
Contractor: Nutech Engineers, Inc.
EPRI Project Manager: H. Tang

Qualified Database for the Critical Flow of Water
NP-4556 Final Report (RP1927-1); $32.50
Contractor: University of California at Santa Barbara
EPRI Project Manager: J. Kim

Annular Array Technology for Nondestructive Turbine Inspection
NP-4557 Final Report (RP1803-3); $25.00
Contractor: Southwest Research Institute
EPRI Project Manager: S. Liu

Fourth International RETRAN Conference
NP-4558-SR Proceedings; $85.00
EPRI Project Manager: L. Agee

Flow-Induced Vibration of Steam Generator Tubes
NP-4559 Final Report (RPS153-1); $62.50
Contractors: Commissariat à l'Energie Atomique; Framatome
EPRI Project Manager: D. Steininger

Cobalt Transport at the Vermont Yankee BWR
NP-4560 Interim Report (RP1934-1); $32.50
Contractors: NWT Corp.; Vermont Yankee Nuclear Power Corp.
EPRI Project Managers: C. Wood, M. Naughton

Fuel and Pool Component Performance in Storage Pools
NP-4561 Topical Report (RP2062-11); $25.00
Contractor: Battelle, Pacific Northwest Laboratories
EPRI Project Manager: R. Lambert

Return of Hideout Chemicals in PWR Steam Generators During Power and Temperature Reductions
NP-4563 Final Report (RPS205-7); $25.00
Contractor: NWT Corp.
EPRI Project Managers: C. Shoemaker, S. Hobart

High-Sensitivity Dissolved-Gas Monitoring System With Applications for PWR Secondary-Side Chemistry
NP-4564 Final Report (RPS306-15); $32.50
Contractor: Radiological and Chemical Technology, Inc.
EPRI Project Managers: C. Welty, S. Hobart

Theoretical Investigation of Pipe Fracture: A Summary
NP-4565 Final Report (RP231-2); $55.00
Contractor: University of Washington
EPRI Project Manager: H. Tang

Validation and Integration of Critical PWR Signals for Safety Parameter Display Systems
NP-4566 Interim Report (RP2292-1); $32.50
Contractor: Babcock & Wilcox Co.
EPRI Project Manager: M. Divakaruni

Study of Microbiologically Influenced Corrosion in Nuclear Power Plants and a Practical Guide for Countermeasures
NP-4582 Final Report (RP1166-6); $100.00
Contractor: Rensselaer Polytechnic Institute
EPRI Project Manager: D. Cubicciotti

Iodine Spiking
NP-4595 Final Report (RP1392-1); $25.00
Contractor: Babcock & Wilcox Co.
EPRI Project Manager: R. Shaw

Chemical Cleaning of Millstone Unit 2
NP-4597 Final Report (RPS305-21); $32.50
Contractor: NWT Corp.
EPRI Project Manager: L. Williams

Effect of Venting on Crevice Cleaning for PWR Steam Generators
NP-4600 Final Report (RPS305-13); $32.50
Contractor: Pacific Nuclear Services
EPRI Project Manager: L. Williams

Application of the Modular Modeling System to Control System Design and Tuning
NP-4601 Final Report (RP2395-4); $25.00
Contractor: Duke Power Co.
EPRI Project Manager: M. Divakaruni

Evaluation of Surface Modification Techniques for PWR Steam Generator Channel Heads
NP-4614 Final Report (RP2296-5); $32.50
Contractor: Quadrex Corp.
EPRI Project Manager: C. Wood

PLANNING AND EVALUATION

Issues Identification and Management: Developing a Research Agenda
P-4488 Final Report (RP2345-28); $25.00
Contractor: J. F. Coates, Inc.
EPRI Project Manager: S. Feher

CALENDAR

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

AUGUST

13–14
Software Integration for Power Systems Analysis
Washington, D.C.
Contact: John Lamont (415) 855-2832

25–27
Nuclear Plant Life Extension Studies
Alexandria, Virginia
Contact: Melvin Lapides (415) 855-2063

25–27
Seminar: Integrated Plant Computer Communications
San Francisco, California
Contact: Murthy Divakaruni (415) 855-2409

27–28
Software Integration for Power Systems Analysis
Seattle, Washington
Contact: John Lamont (415) 855-2832

SEPTEMBER

9–11
Seminar: Fossil Fuel Plant Inspection
San Antonio, Texas
Contact: John Scheibel (415) 855-2850

9–11
Workshop and Seminar: Bearing and Rotor Dynamics
St. Louis, Missouri
Contact: Stanley Pace (415) 855-2826

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

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

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