Inside the Smart House

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Cover: Touch-screen displays will update the homeowner on the energy, safety, and security status of specific areas in the Smart House and allow him to program the control of individual appliances and services.

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Designing the Electronic Home

Lannus

Many of us can remember when the home of the future meant an all-electric house, with heating, cooling, and household chores accomplished easily and efficiently with shiny new electric appliances. Now, with semiconductors revolutionizing many facets of American life from the family car to the office and factory floor, the home of the future means an *electronic* house.

In fact, microprocessor-chip intelligence is already found in everything from microwave ovens and dishwashers to home entertainment and security systems. With such electronic controls now appearing in many appliances, the next step is to tie them all together in a sort of network for power, data, and control that can bring their full potential for convenience and efficiency to reality. Such is the goal for the 1990s of an ambitious and exciting cooperative venture of home appliance and electronics firms under the management of the National Association of Home Builders Research Foundation.

The Smart House project, featured in this month's cover story, aims to rewrite the book on home electric wiring to enable nearly every appliance in a house to be scheduled, controlled, or monitored through a central, microprocessor-based system. Participating manufacturers are designing to a common technical standard new versions of home appliances that will contain distributed intelligence and communicate with higher-level microprocessors through an integrated, multiconductor wiring system that carries audio, video, and data signals as well as electricity.

In addition to the unprecedented levels of convenience and control that the Smart House concept offers home buyers, the technology will harmonize with developing utility industry plans for residential load management, including new rate structures that reflect the time-varying cost of electricity generation. In the next decade, Smart Houses will be programmed to take advantage of time-of-use rates by operating large appliances when it is both economical and convenient. And utilities may be able to tap the electronic brains of Smart Houses for detailed information on the use of electricity in the home.

The clear potential is for a new dimension in the relationship between utilities and their residential customers, allowing real-time electronic interaction in an energy marketplace where information is as important as the commodity. As the technical representative of the electric power industry in this venture, EPRI is enthusiastic about the prospects of the electronic home of the future: the Smart House promises a win-win situation for appliance makers, homebuilders, utilities, and home buyers alike.

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The Smart House: Wired for the Electronic Age (page 4) is a freeze-frame look at fast-moving R&D, market development, and electricity code revisions that will soon give new meaning to all-electric living. Written by Taylor Moore, senior feature writer of the *Journal*, aided by staff of EPRI's Energy Management and Utilization Division (EMU).

Veronika Rabl manages research projects in load management technology, largely for residential and commercial applications. Before joining the Energy Utilization Department in 1981, she was with Argonne National Laboratory for nearly seven years, mostly in energy technology assessment. On assignment from Argonne in 1980–1981, she managed a program of technical and economic analysis for the DOE Office of Energy Systems Research. Rabl graduated in physics from the Weizmann Institute of Science in Israel. She also has a PhD from Ohio State University.

Orin Zimmerman is Technical Director for Energy Utilization, working to integrate research of EMU and other EPRI divisions that has implications for electricity end use. Zimmerman has been with EPRI since 1979, including a year and a half on loan from Portland General Electric Co. at the end of his 33-year career there. He worked in PGE operations, distribution engineering, and sales, becoming general manager for conservation and energy management. Zimmerman is an electrical engineering graduate of Oregon State University. ■

Adapting Energy Technology to the Future (page 16) reviews major points of the commercial context that is shaping EPRI's technology developments for the turn of the century. Adapted by Ralph Whitaker, *Journal* feature editor, from a speech by the director of EPRI's Planning and Evaluation Division.

Richard Zeren began work at EPRI in 1974 as assistant to the division director for fossil fuel and advanced power systems. During 1980 he was a senior associate with Booz, Allen & Hamilton, Inc., returning to EPRI in his present capacity. Zeren was formerly on the engineering faculty of Michigan State University. He has a BS in mechanical engineering from Duke University, and he earned MS and PhD degrees in the same field at Stanford University. ■

Getting a Fix on Lightning Strikes (page 24) explains a regional data network that has logged 10 million lightning flashes in three years, serving now as an early warning system for utility repair crews and, eventually, as a design basis for choosing and locating surge protection. Written by Michael Shepard, *Journal* feature writer, with background from the Electrical Systems Division.

Herbert Songster has been a project manager in the Distribution Program since he joined EPRI in 1978. He was formerly with Philadelphia Electric Co. for 31 years, working successively in electrical operations and electrical engineering and taking responsibility for a number of standards and specifications for distribution apparatus. Songster has a BS in electrical engineering from Drexel University. ■

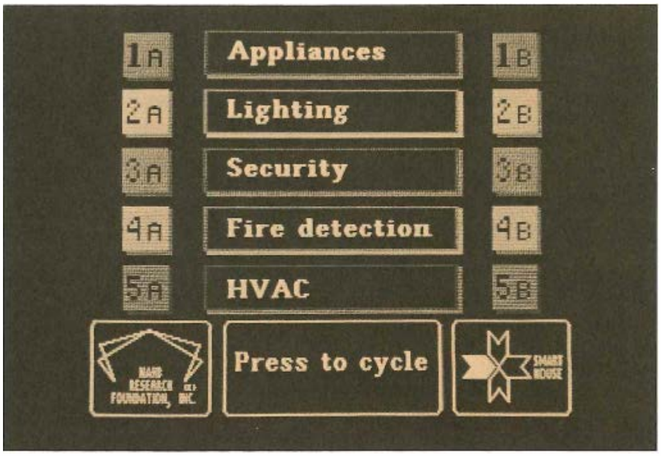
System Reliability: Seeing the Whole Picture (page 30) reviews the piecemeal development of reliability indexes and today's work toward composite models that integrate many more variables. Written by John Douglas, science writer, with technical input from two research managers of EPRI's Electrical Systems Division.

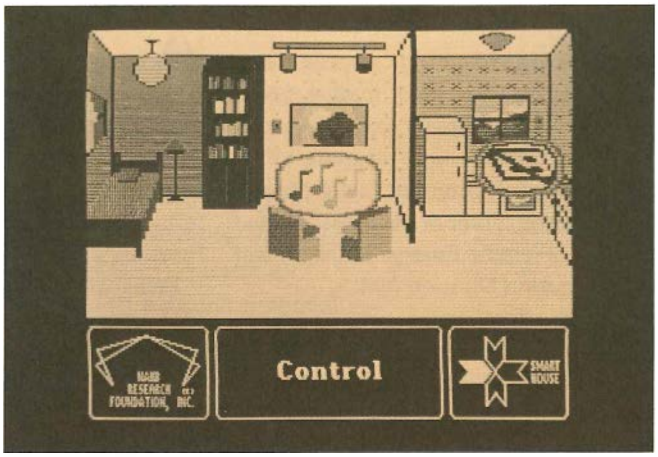
Neal Balu manages the system planning research subprogram. He came to EPRI in 1979, following seven years in the system planning department of Southern Company Services, Inc., where he headed the system dynamics section. Earlier, he spent four years on the faculty of the Indian Institute of Technology in Bombay. After coming to North America, Balu earned three graduate degrees in electrical engineering, including a PhD at the University of Alabama, and an MBA at Santa Clara University.

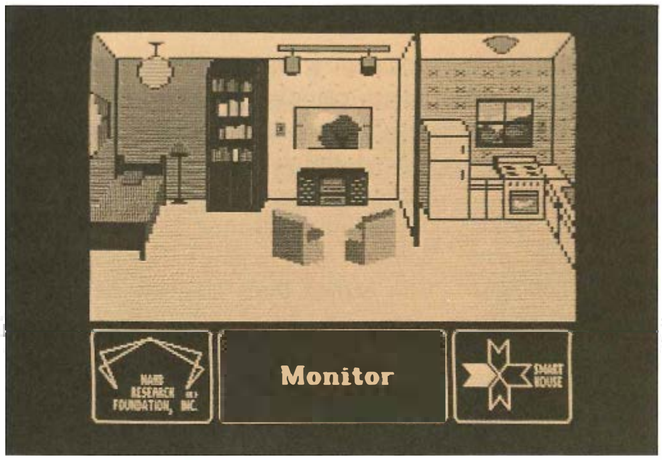
Robert Iveson, manager of the Power Systems Planning and Operations Program, has been with EPRI since 1979. He was formerly with New York State Electric & Gas Corp. for 20 years, including 9 years as supervisor of transmission planning for the New York Power Pool. Iveson graduated in electrical engineering from Rensselaer Polytechnic Institute and earned an MS from Syracuse University. ■

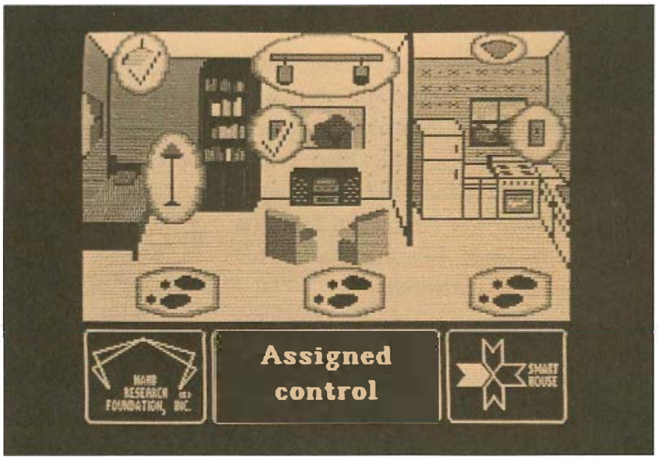
THE SMART HOUSE

WIRED FOR THE ELECTRONIC AGE









Centralized microprocessor controls are coming into the home, offering unprecedented levels of convenience, comfort, and safety. The Smart House concept is expected to open the door to new interactive relationships, not only between homeowners and their appliances but also between utilities and their customers.

Half an hour before you rise, the water heater turns on to reach just the right temperature in time for your shower. Bedroom and bathroom lights turn on as the radio wakeup alarm sounds. The rooms you use at that hour have been preheated. The coffee maker comes on while you're in the shower; when you finish, you're greeted by a full pot, and the television is on with your favorite news show.

During the day, as it warms up outside, the air conditioner keeps the indoor air comfortable if anyone is home but avoids running in a two-hour afternoon peak period when electricity rates are highest; the dishwasher that was loaded the night before runs itself early in the morning. A security system keeps watch while you're away but decides not to call the police when a neighborhood kid tosses the evening paper against the front door.

When you return, recorded telephone messages are played back over the bedroom speakers while you change, but soothing music fills the den where you relax. A flashing light on a video screen announces that dinner in the microwave is ready. As dusk falls, outdoor lights turn on, the garden sprinkler gives the begonias a drink, and during commercials on the evening news you watch a display on the screen of the day's energy consumption and costs.

Before you retire, the screen provides a status check of all outside doors and locks. The house turns off all nonessential appliances that were on, save for the reading lamp over the bed. Room occupant sensors automatically light the hall and kitchen if you venture out of bed for a nocturnal glass of milk.

Such is one of many possible scenarios that may be commonplace to new homeowners in the 1990s if an ambitious R&D effort now under way is successful. The Smart House Development Venture, a project of the National Association of Home Builders (NAHB) Research Foundation, is aimed at nothing less than the total integration of microelectronics and power semiconductors into the fundamental design and construction of most of the 1.6 million new homes built annually at the current rate.

Home smart home

Microprocessors—those computer-on-a-chip workhorses of the silicon revolution that are changing all sorts of industrial and office technology—are already cropping up throughout the house, too. Increasingly, they provide control and limited intelligence in everything from microwave ovens, home entertainment, and security systems to hot water heaters and heating, ventilation, and air conditioning (HVAC) systems.

Typically, though, the smart chips in modern appliances do not communicate with one another. Engineers and home builders have long known that is the key to making a house smart. In fact, the steadily increasing computing power and the dropping price of microprocessors and semiconductor switches have already led to a growing market in home automation devices and systems that topped $300 million in retail sales in 1985, according to industry analysts. That was the year the concept of smart dwellings became an industry, proclaimed *Electronic House*, a new magazine that caters to the home hobbyists and technology enthusiasts who now form the bulk of the market. Earlier this year, the Intelligent Buildings Institute was formed to serve a wide professional constituency covering all types of smart structures.

A number of companies, from small mail-order operations to such giant manufacturers as General Electric Co. and Honeywell Corp., are on the market with computer-based home command and control systems with such names as HomeMinder, Smart Home, and Home Brain, as well as security, entertainment, and water and energy management subsystems. Most often sold as retrofits to existing homes, the gadgets connect appliances, outlets, and lights to a central controller that can be user-programmed or monitored from a computer screen or push-button panel. Most are designed to overlay and (in some cases) make use of the cat's cradle of electric and twisted-pair wiring and coaxial cable that increasingly clutters or crowds corners and baseboards.

The NAHB Smart House, however, intends to take it all to the ultimate: an integrated home wiring system that carries power, voice, audio, video, and data transmission signals on a single set of conductors linked by distributed microprocessors that in turn communicate electronically with virtually every other electric-powered or electronically controlled appliance in the house.

The result, project officials say, will provide an unprecedented degree of comfort control, convenience, and safety, as well as open the door to innovative applications of microelectronics in the home as unimagined today as were the diverse roles unforeseen for electricity when it first began to supplant oil and gas lighting in the late nineteenth century.

One application of microprocessor control that is being designed in from the start will dovetail directly with emerging plans of electric utilities for residential load management programs, including innovative time-of-use rates. Because a Smart House will be largely programmable, it could follow preset instructions or learn to operate energy-consuming appliances on a schedule that takes advantage of lower energy costs at off-peak periods while maintaining or even improving occupant comfort levels.

For electric utilities searching for alternatives to building new power plants to satisfy growing peak demand, the technology envisioned for the Smart House represents a key step toward a new dimension in their relationship with residential customers. The microelectronics will permit two-way data communication between utilities and customers, allowing utilities to better understand the residential energy sector, as well as operate generating systems more efficiently, and permitting customers to take a more active, decision-making role in the energy marketplace by optimizing their personal patterns of energy use for economy and convenience.

As both a research sponsor and as technical representative of the electric utility industry, EPRI is playing a major role in the Smart House project. Working closely with the project staff and contractors based at the NAHB Research Foundation in Upper Marlboro, Maryland, and at Cambridge, Massachusetts, EPRI's Energy Management and Utilization (EMU) Division is helping to develop specifications for the integrated wiring system, as well as software and some of the hardware for the load management aspects of Smart House design.

"The common denominator for electric utility interest in the Smart House is a market opportunity for the use of electricity," explains Veronika Rabl, EPRI project manager. "But it is also a once-in-a-lifetime chance to have an influence on the ground floor of the building industry's effort to redefine the use of technology in the home for many generations to come. We want to make sure that the objectives and concerns of utilities are addressed and incorporated to the extent possible in this home of the future. Because of the organizational nature of the project and the full backing of NAHB, we think the Smart House will become the standard for the home of the future." Smart Houses are expected to begin showing up in new home construction in the early 1990s.

Wired for intelligence

The idea of making a house smart with microprocessors has been around in some people's minds since early buyers of personal computers (PCs) wondered if their computers did such a great job

Benefits on Both Sides of the Meter

Smart House technology benefits homeowners and utilities alike, although the nature of the benefits is different, depending on which side of the customer meter is considered.

BENEFITS TO HOMEOWNERS

Entertainment: Integrated wiring permits audio and video signals to be distributed throughout the house. Stereo speakers or video monitors can be plugged into any outlet. Television screens can double as control system displays.

Security: Electronic locks and sensors for occupancy/intrusion, temperature, and smoke can be tied into microprocessor controls to alert a homeowner or to automatically call police or fire-fighting services. Homeowners could check the status of all outside doors or windows from a video display screen or remote control panel. Home security could be as sophisticated as desired.

Convenience: Common bus wiring permits a homeowner to designate any wall switch for controlling lights or appliances throughout the house. Outlets provide electric power and control and data signals, as well as audio and video signals. Security features could be expanded as needed without additional wiring. Homeowners could exercise control functions remotely over telephone lines. Speech recognition and voice synthesis systems for user interface are envisioned for the blind or otherwise physically handicapped.

Energy management: Automatic environmental control over the whole house or selected rooms is possible through the interplay of sensors and control programming. Control systems could be programmed or trained to take advantage of time-varying utility rates and operate large appliances and HVAC systems at the most economical periods.

Safety: Closed-loop power distribution cuts off power to malfunctioning or short-circuited appliances, reducing fire hazard, and denies power to unrecognized appliances (e.g., a child's toy), virtually eliminating shock hazard.

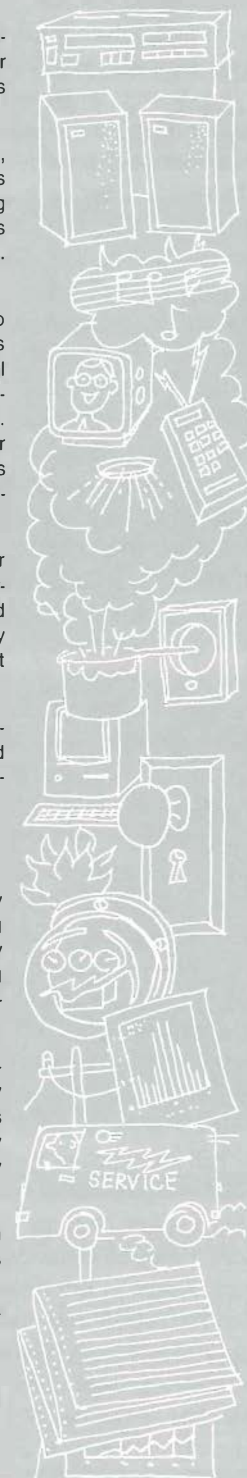
BENEFITS TO UTILITIES

Load management: Interactive communication allows a utility to transmit price signals to customers that reflect time-varying costs of service and permit customers to optimize home energy use. Electricity demand peaks could be flattened, while raising overall load factors. Utilities could exercise real-time control of residential loads or defer peak loads through communications links.

Load data acquisition: Energy-use data on residential appliances and entire homes may be periodically retrieved by a utility over power or telephone lines, reducing the cost of end-use studies and providing a more-accurate account of residential energy demand for utility planning. With appropriate hardware, utility meters could be read remotely.

Safety: Utilities could be automatically notified of a problem with electric service. During repair or service, individual branch circuits can be deenergized, eliminating the need to open the main circuit at the service entrance. Each branch circuit controller would have a ground fault interruptor for increased protection.

Marketing: Smart House technology provides a systems framework for integrating electric-powered and electronically controlled home appliances, and it emphasizes the convenience, flexibility, and economy of well-managed electricity use.



of word processing and juggling checking accounts, could they not also set the thermostats, schedule the washing machine, turn on the lights when no one was home, and put the cat out at night? Indeed, some hobbyists have adapted PCs to do much of that, although usually PCs must be dedicated to one or only a few functions. Today, however, there are several products available for home command and control that are essentially dedicated microcomputers, some with sophisticated software and video displays. None of them can yet put the cat out, though.

Some people understood early on that intelligent use of miniaturized integrated circuits could do much more than simply turn things off and on. If made smart enough, a house could sense the type of appliance plugged into any outlet and deliver only the current level appropriate to run that appliance. Or, lacking the necessary signature of a power appliance, it could decide not to energize an outlet with a child's finger or toy inserted.

Such a level of electronic intelligence, however, implies a radical departure from conventional home electric wiring, which has advanced little in the last 50 years or so and is involved in an estimated 400 electrocutions and thousands of residential fires annually. If that is not reason enough to think about wiring redesign, cost represents another important factor. Many homes may have half a dozen types of wire, cord, and cable snaking through walls and under floors for alarms, electricity, stereo speakers, intercoms, telephones, and other services. Integrating them under a common bus would not only bring all the services to any room but also cost less to install.

But fundamental changes in residential wiring would mean rewriting the National Electrical Code, the electrician's bible maintained by the National Fire Protection Association. And if electrical standards are to change, appliances themselves must be redesigned to incorporate microprocessor chips both to get smart and to signal some higher-level control device the type and amount of power required.

David MacFadyen, president of the NAHB Research Foundation, is generally credited as the driving force in organizing the Smart House venture, although he modestly insists his role has been mainly as a catalyst. In late 1984 MacFadyen invited over 100 manufacturing firms, trade associations, and government agencies to talk about coordinating and designing to a common technical standard what many of them had already begun to do or to think about for their next-generation products. The idea was for a cooperative development effort, backed by the 142,000-member NAHB with its extensive network of builders, manufacturers, and state trade associations, that would help bring Smart House products and technology to market, as well as nationally promote the home of the future and train building contractors in its construction.

"Our intent wasn't to do a Smart House per se but to rethink how houses are built so that utilities and product manufacturers could do a better job of satisfying their customers," explains MacFadyen. "That is really the concept—a focal point for bringing everybody together. We simply designed a process that appears to be working well."

A potentially major legal and economic inhibitor to such an approach had just been eliminated when the NAHB Research Foundation proposed the Smart House venture. Congressional passage in 1984 of the National Cooperative Research Act (proposed by the Reagan administration to partly counter the government-sponsored industrial R&D that was giving a competitive edge to European and Japanese firms) greatly reduced the legal risks associated with possible antitrust law violations for companies that took part.

The act has thus far spurred about 50 major cooperative ventures, including the Smart House project, says Bruce Merrifield, assistant secretary of commerce for productivity, technology, and innovation, and the legislation's principal advocate. "When the Microelectronics and Computer Corp. was set up a few years ago in Texas by that industry, the company spent about a quarter of a million dollars in legal fees to work out the antitrust issues." Similar obstacles faced the utility industry when EPRI was established in 1972. "Antitrust laws designed over 100 years ago are antithetical to survival in a global market," adds Merrifield.

"The cooperative research act allowed us to get by for less than $100,000 in antitrust legal work, and by removing liability for treble damages for participants, it induced some manufacturers to participate who normally would not have taken the risks," comments NAHB's MacFadyen.

In a little less than two years, nearly 40 manufacturers of electrical, electronic, and gas-fired home products have signed on with the Smart House venture; in effect they are contributing product development work in return for license rights to market Smart House–approved and –compatible appliances and components. For seed money NAHB provided $2 million, and its research foundation subsidiary added another million. In addition, according to Barbara Sampson, general manager of the Smart House project, a private offering to raise capital is expected to bring another $30 million by the end of this year. "Counting the value of what the participating firms will contribute, altogether we're looking at an effort of as much as a $150 million over two to three years," Sampson adds.

The roster of participating firms includes many familiar names in home appliances, including Carrier Corp., General Electric, Honeywell, Lennox Industries, Inc., North American Philips Corp., and Whirlpool Corp., as well as computer and electronics industry

Mobile Smart Rooms: Traveling the Circuit

To demonstrate many of the functions and features of Smart House technology, EPRI and the Gas Research Institute have cosponsored with the Smart House project two Mobile Smart Rooms—working mockups in tractor-trailers that have been on the road this past year at home builders' conventions, trade shows, and public exhibits. One features all-electric appliances, while another includes electronically controlled gas service for heating and cooking. The Mobile Smart Rooms contain early versions of the special wiring and control panels and displays that home buyers will find on the market in the 1990s.

heavyweights Apple Computer, Inc., AT&T Technologies, Inc., National Semiconductor Corp., Northern Telecom Co., and Signetics Corp.

An extensive advisory council represents special interests among potential Smart House dwellers, as well as industries that stand to be affected by the advent of Smart House technology. The list includes the federal government's administrations for veterans and the aged, Consumer Product Safety Commission, National Bureau of Standards, and Department of Commerce. Utilities are represented by the American Gas Association and Edison Electric Institute, whereas the Gas Research Institute and EPRI are involved at the technical level. Smart House designs will accommodate the latest in gas as well as electric appliances. Ontario Hydro, Potomac Electric Power Co., Southern California Edison Co., and Wisconsin Electric Power Co. are utility members of the council.

The last major hurdle before the project could gear up to full steam was crossed in late 1985 when first-round changes were approved to incorporate Smart House wiring concepts into the 1987 edition of the National Electrical Code. "This represents the first major change in the code in years," notes Orin Zimmerman, technical director of EPRI's EMU Division. "Now we have a conceptual umbrella for manufacturers to design products. The code will recognize the concept of closed-loop energy distribution in which branch circuits are not energized except when actually operating an appliance.

"Closed-loop distribution works with microprocessor chips in the appliances themselves to introduce whatever voltage or current levels are needed for that appliance. A lot of appliances can then be designed with fewer controls and simpler motors, reducing cost by as much as a third. For the first time we can see the integration of digital controls with the home energy system. Smart Houses will require fewer ground fault interruptors. With closed-loop control the possibility of electrocution or a short circuit that could cause a fire is virtually eliminated."

Not smart yet

Getting approval for revision of the electrical code was particularly difficult, according to Zimmerman, because no Smart House products yet exist on any home appliance store shelf or display floor. "The code committees don't like to make changes until there is hardware in place." But the initial revisions have laid enough of the technical groundwork to give a green light to Smart House participants to forge ahead with product design and development.

By the same token it would be difficult to interest home builders and new home buyers in a Smart House if all that were available for show-and-tell were design drawings and descriptive specifications. Full-scale prototype Smart Houses are not expected until late 1988, with about 100 demonstration models expected to be built around the country in 1989.

Meanwhile, to promote the concept and demonstrate some of the functions to home builders and, eventually, to the public, the project has constructed two Mobile Smart Rooms—48-ft (17-m) tractor-trailers outfitted with the special wiring, appliances, and control systems. One version, cofunded by the Gas Research Institute, features electronically controlled gas appliances. EPRI cosponsored construction of an all-electric model. The Mobile Smart Rooms have gone on the road to home builders' conventions and trade shows, where they were the hit of the year.

Smart House features

The key to intelligence in a Smart House lies in its wiring and power distribution system. Rather than have all circuits originate from a single point, as in a conventional house, the Smart House concept calls for branch circuit controllers, each containing microprocessors distributed throughout the house and feeding a number of branch circuits. Each controller distributes programmed power to a cluster of rooms or to a group of appliances—laundry or kitchen appliances, for example.

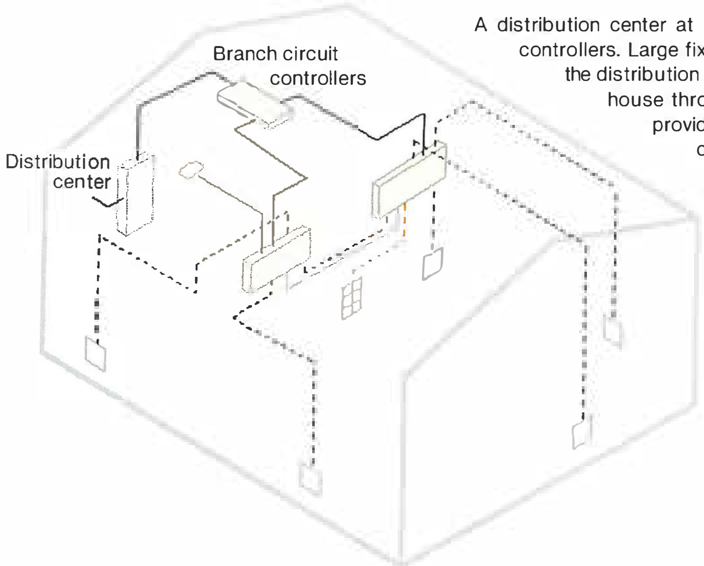
The controllers energize the branch circuits only when an appliance on a circuit requests power. The controller can sense when current limits are exceeded (as in an appliance malfunction or a short circuit) and cut off power immediately. Smart Houses will not restrict appliances to standard 110-V ac power; a branch controller could also understand an appliance request for low-voltage dc and supply 48-V dc to, say, a clothes washer, a power tool, or nonballasted fluorescent lights. Smart House designers also envision an uninterruptible 12-V dc power source, possibly backed up by batteries and photovoltaic panels, that would keep the house control system and certain subsystems, such as alarms, functioning during a power outage. Ground fault protection is provided for all branch circuits by a single interruptor at each branch controller.

According to project officials, smart appliances are expected to be cheaper and safer and to offer greater capability by using dc power and microelectronic intelligence, although EPRI has some reservations about the cost-effectiveness of distributing and controlling dc in a house. The lower dc voltages could reduce shock hazard, as well as fire hazard. In addition, Smart House controls will supply timing, eliminating the need for built-in timers in every appliance. Sophisticated self-diagnostic and service reminder functions are possible.

Lest customers think they would have to buy all new smart appliances for a Smart House, project officials are quick to point out that simple adapters are being designed for conventional appliances that will allow them to plug into and operate from the special outlets. Adapted conventional appliances might not have the full functionality of

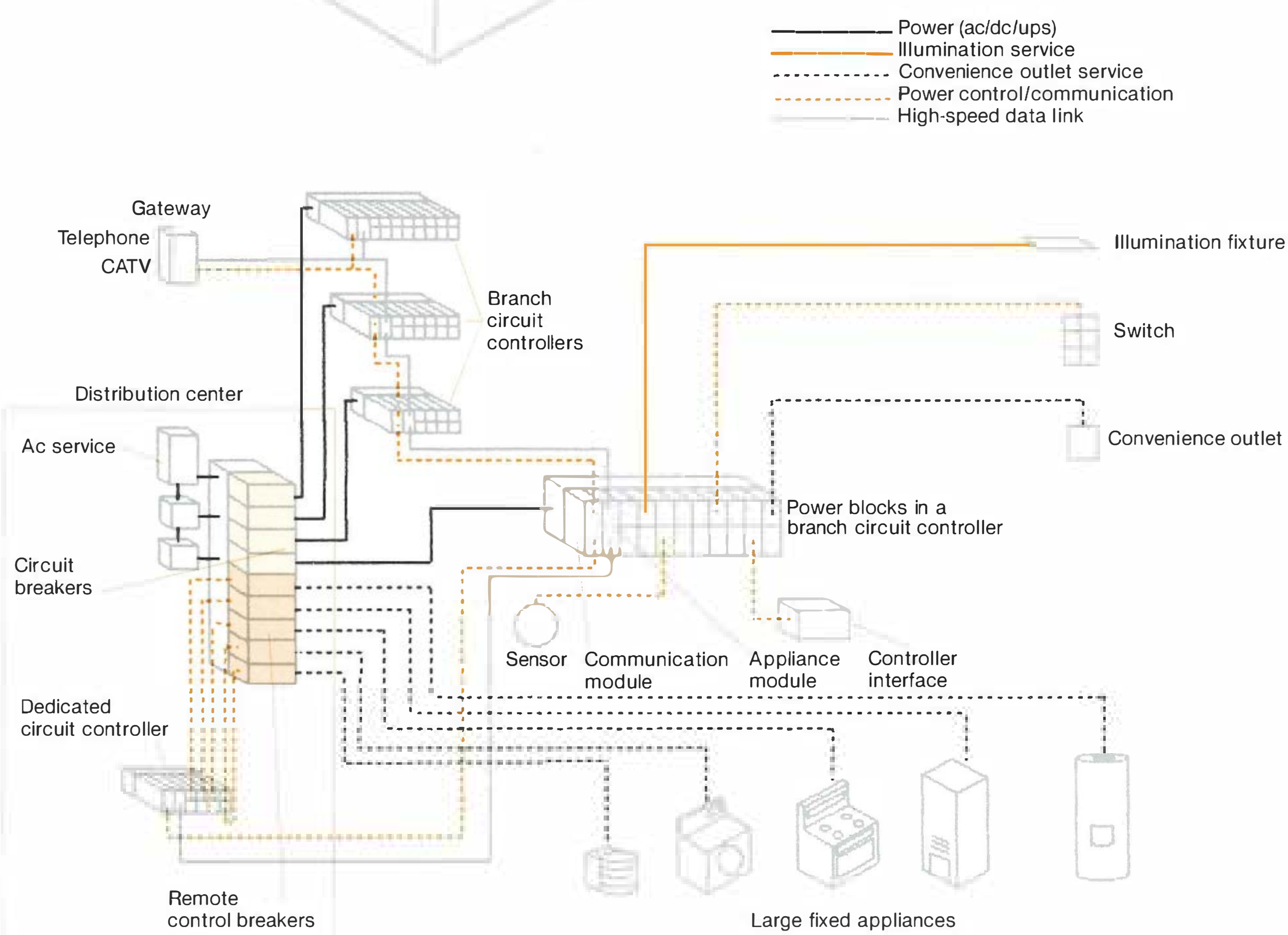
Smart House Design: A Look Inside

Distributed microprocessors and multiconductor wiring are the brain and central nervous system of a Smart House. As indicated in this preliminary functional diagram, a typical Smart House may have up to eight branch circuit controllers providing distributed intelligence and power, data, and audio/video signals to individual rooms or clusters of rooms. This is in contrast to normal wiring, in which all circuits originate at the power service entrance.



A distribution center at the house service entrance powers all the branch circuit controllers. Large fixed appliances are connected directly to circuit breakers at the distribution center and may be remotely controlled from anywhere in the house through a dedicated control module. The distribution center provides the branch controllers with standard-voltage alternating current (ac), low-voltage direct current (dc), and an uninterruptible dc power source (ups) for control functions.

Each of the other branch circuit controllers contains up to 16 power blocks for powering and communicating with lights, sensors, switches, convenience outlets, or control panels. Some circuits, say, for light fixtures, may provide only electric current, while appliance circuits would carry both power and data. Together, the branch circuit controllers form a highway for data and control signals, each controlling specific circuits for lights, outlets, appliances, and switches, and are capable of control programming from any location.



the smarter models, but they would work at least as well as they do now. The integrated receptacles, carrying voice, audio/video, and data signals, as well as power, for example, would allow a telephone answering machine to receive power and telephone service through a single plug.

Moreover, the machine could operate from any receptacle in the house. Likewise, stereo speakers or a television monitor could operate in any room regardless of where the receiver sets were located. Signals from hand-held remote controllers would be transmitted over the circuits back to a receiver to change channels, activate a video cassette recorder, or turn a set off.

Closed-loop power control will also permit wall switches to be functionally rather than physically associated with outlets and appliances. Switches are being designed as low-voltage signaling devices that communicate with the branch circuit controllers. Thus, someone in a bedroom could designate a wall switch there to turn off all other lights in the house. Or activation of a potentially dangerous appliance from a switch in another room could be specifically prohibited by control programming.

Sensors in the Smart House are almost as important as switches. Sensors of any kind (occupancy/intrusion, temperature and humidity, light, and smoke) can be installed anywhere and reinstalled as needs change. Because they are tied into the programmable controllers, their capabilities are magnified. Thus, an occupancy detector could turn a light on if a room is entered while it is dark and someone is supposed to be home or, instead, call the police if no one is supposed to be home.

The branch circuit controllers and all communications services are connected in a unified bus either to a central controller at the service entrance to a Smart House or to two or more distributed controllers. The bus resides in a multiconductor hybrid cable that includes a high-speed digital data link for Smart House internal control, analog telephone and intercom conductors, conductors for audio distribution, coaxial cable for video, and a high-speed general-purpose digital link. Smart House designers say the central control–communications bus will be fiber-optic capable, meaning that very high speed digital capability can be easily incorporated into the system when fiber-optic technology becomes cost-effective in the future.

The central or distributed controllers will feature an intelligent user interface that allows occupants to query the system or reprogram various functions. This interface may be through a TV set, a home computer, or a dedicated terminal, such as the touch-screen type included in the Mobile Smart Room displays. Experts point out that personal computers are not required for Smart Houses but can be used as part of the system, if desired.

Digital electronics inherent in the Smart House will also permit the ultimate in user interface: voice recognition and speech synthesis. Designers say this option should be particularly attractive to such special categories of potential Smart House dwellers as the blind or the elderly. For example, a Smart House could be programmed to summon aid (call for an ambulance or the police) on voice request or if there has been no user input to the system after a specified time. Similarly, the house could tell a blind person the status of various appliances, warning that a stove burner was on, for instance. A homeowner could also interact remotely with the Smart House over telephone lines.

Energy management

The greatly expanded dimension of control in a Smart House, both over the total system and over individual appliances and switches, opens the door to possibilities in home energy management that have been anticipated for some time. Energy analysts have long noted that increased use of information in the form of digital data and control signals could make even the most physically energy-efficient house even more so by intelligent scheduling of appliance and HVAC system operation. Homes are the point of consumption of about 35% of all the electricity used in this country and account for 8.6% of total primary energy use.

Utilities around the country are planning more-extensive conservation and load management programs as alternatives to construction of new generating capacity because of load management's potential for flattening peak demand while improving overall load factors. Innovative, real-time pricing of electricity is in limited experimental use in some areas; effective widespread application requires communication of changing price signals from the utility to the customer and appropriate electric meters.

For utility planners, the Smart House is an answer to their prayers: its potential represents the missing link in residential load management by offering distributed load control capability interacting on a real-time basis with the utility. In this sense, Smart House load management is even more sophisticated than the elaborate electronically controlled energy management systems now found in many large commercial buildings.

The Smart House will have the ability to automatically take account of virtually any rate form and control discretionary appliance operation. Homeowners may not even have to bother with programming the control system with the rate schedule—that could be supplied over telephone or power lines directly from the utility. "One aspect that has limited the advent of residential load management is the cost of the equipment, sensors, and wiring needed for more-sophisticated forms of load control. In the Smart House, these costs could be virtually eliminated because installation of a system would consist mainly of programming the controller," says Rabl.

A word on gas: as in the case of electricity, a Smart House could, if desired, supply gas throughout the house from a central controller. Gas appliances would provide operating signals to electronic controls that request a certain flow rate or to cut off flow if the requested rate is exceeded. Project officials say gas distribution inside most of the house may be through flexible, cheaper-to-install tubing rather than through iron pipe.

A key role EPRI has played in the Smart House project involves funding the development of technical specifications for the smart controls for electric load management and utility communications links to transmit data to the controller and retrieve data on end-use electricity consumption.

The basic Smart House approach envisions a telephone link to permit the homeowner to remotely control some of the functions in the house. EPRI is working to include a capability to link the Smart House with other communications systems more commonly used by utilities, such as radio and power line carriers. The continuous monitoring of individual appliance electricity use, inherent in the Smart House design, gives utilities the potential for lower-cost end-use data acquisition. With the homeowner's permission, the data might be stored and periodically retrieved by a utility through the communications link.

EPRI's work with the Smart House will build on earlier studies of the various types of load control strategies being explored for implementation in the future. Elements include development of a load control emulator for utilities to test a wide variety of load control strategies; control algorithms that can be encoded in the control emulator or on memory chips in Smart Houses; and new ways to monitor residential energy use for evaluating the effectiveness of load management. Load control technology developed under the EPRI projects will also be adapted for use in conventional homes.

An initial version of a load control algorithm is already being displayed to utilities in a special section of the electric Mobile Smart Room. As Rabl explains, "The goal is to define a price-responsive control logic designed to minimize a customer's energy bill under various pricing schemes, including real-time or spot-pricing.

"The simulation in the Mobile Smart Room compares cost, energy consumption, and load factors of a house under conventional electric rates with those of a house under a real-time rate schedule now under experimental test at Georgia Power Co."

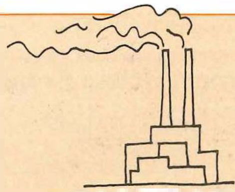
EPRI plans to pilot-test control emulators in 1987 on four or five conventional homes in the service territory of Arizona Public Service Co., which already offers demand-based electric rates to residential customers. "The emulator is a general-purpose control device designed to facilitate a comprehensive field evaluation of the various control strategies," Rabl explains. "Market-oriented hardware development can follow, once the most effective applications and their limitations are defined. The final hardware product will likely use many of the elements of the emulator." A prototype controller for the Smart House is expected to be tested in 1987 or 1988, with an advanced model for conventional homes to follow in the early 1990s.

F. C. Schweppe, a professor of electrical engineering at the Massachusetts Institute of Technology and one of the early proponents of spot-pricing electricity, works with EPRI on developing price-responsive control software. "First, we need to find out from the customer what the customer wants. Then, we want to develop software that can learn a rate schedule; optimize the temperature-dollar or comfort-cost trade-off inherent in a price-based mar-

Electric utilities familiar with the Smart House Development Venture are excited by the prospects for home automation, particularly with the technology's potential for helping to realize the full benefit of residential load management programs. Some utilities are directly involved with the Smart House project as corporate sponsors, while others plan to work with it to outfit and evaluate prototype models in the next few years. EPRI has set up a utility advisory committee to guide its own involvement in helping define Smart House technical standards. A sampling of utility views reflects an apparent consensus that the Smart House may be the wave of the future in home energy management.

"The Smart House will enable us to implement various residential rates, such as time-of-use pricing, more easily," says Brian Brady, manager of energy management technical services at Southern California Edison Co., a member of the Smart House Advisory Council. "Currently, we don't have a reliable and economical technology for the utility-customer interface."

Brady says SCE now has direct load control on more than 100,000 air conditioners in its service area, representing a little over 200 MW of load, but adds, "The Smart House concept would give the customer a better choice than with our present demand-side management programs. It's not



UTILITIES CATCH THE WAVE

the only game in town, but it seems to be the only complete package."

At the heart of utility interest in smart controls for home energy management is the potential for flattening peak demand, shifting some of the energy load for such large household appliances as air conditioners and water heaters away from the critical hours of the day when power is most expensive to generate. "A Smart House should have a substantially higher load factor. It might, for example, use the same number of kilowatthours but have a lower peak load, which would help make operation of the utility system more efficient by spreading demand out over the day," notes A. Michael Maher, who heads energy management development at Potomac Electric Power Co. Pepco has tentatively agreed to help instrument a laboratory model Smart House to be built at NAHB's National Research Home Park in Bowie, Maryland, beginning late this year. We do have some concerns about the power system and they are being addressed in the Smart House system design.

"The customer's microprocessor controller should be protected from unwanted signals from outside the house, while signals resulting from customer-utility agreements are honored. The use of dc power converters in the house could cause some interference back on the utility line or next door, but these are issues for which solutions exist. The Smart House does have good energy management potential and it will make time-of-use rates more economically feasible," Maher says, noting that Pepco already offers time-of-use rates to over half its customer revenue base in the District of Columbia and has plans to extend them to other areas.

The other key attraction of the Smart House for utilities is to tap its microelectronic brain for detailed, accurate energy end-use data. "Load research costs us a lot now," Maher continues, "but with permission from a Smart House owner, we could learn a lot more about how power is used in the home and be able to set rates more appropriately and plan for the future more efficiently."

In Pacific Gas and Electric Co.'s vast service area, about 25,000 residential customers have been participating in a time-of-use rate experiment since 1984. "Initial results are favorable, although the cost of time-of-use meters is still relatively high, and products to help customers automatically schedule their large appliances are relatively scarce," says Gary Fernstrom, assistant to the PG&E vice president for customer operations. "The Smart House project is developing home energy management technology, which may help customers gain the maximum benefit from time-of-use and other types of rate options. The research effort also promises to lower home wiring costs, facilitate computerized control and communications, and improve electrical safety," Fernstrom adds. "The Smart House concept supports our vision of the future in which the price of electricity will be closely related to its cost at the time of production, and customers will use advanced electronic technology to manage their energy use."

Another utility closely monitoring Smart House developments and also experimenting with real-time electricity pricing is Georgia Power Co. This Southern Co. subsidiary now applies a four-tier rate on over 100 customers in Roswell, Georgia, where rates are less than the current average residential rate most of the time; a fifth of the time, however, when generating costs are high, they pay much more than the average rate. A microelectronic controller with optimization routines allows a customer to program the system to take full advantage of the rate.

"Customers are reacting very positively," reports Richard Mathisen, manager of strategic market planning and research at Southern Company Services, Inc. "When the rates are high, they're letting the comfort setting on the air conditioner rise, while setting the temperature lower for discounted periods." Mathisen calls the Smart House "an exciting technology product worth watching for breakthroughs that might affect the future of the electric utility business." □

ket decision, anticipating peak-period pricing; and adapt that optimization to the individual nature of the customer's house." Amazingly, all the logic and necessary information to carry out the kind of complex adaptive control Schweppe describes will be encoded into one or more microprocessor memory chips.

A smart market?

Clearly, what most interests utilities about the Smart House is different from what most likely will interest prospective home buyers who will be offered Smart Houses in the 1990s. What of that market? What will being smart add to the cost of a new home? Will home buyers go for it?

The most likely first buyers of Smart Houses will fall into the market category often called upscale consumers, analysts say, those buyers who are above-average earners looking for an above-average home and attracted to innovative technology. But as more Smart Houses are built, project officials are confident that they will become the talk of the neighborhood and will be seen not just as the latest thing but as the smart choice of many prospective home buyers.

If interest among home builders in the traveling Mobile Smart Room displays this past year is any measure, home buyers will certainly find the Smart House attractive on a number of levels. The Smart House venture has already sponsored two major studies of the potential market, one by the Yankee Group in Boston and one by Yankelovich, Skelly and White in New York City, and the outlook is more than encouraging.

Howard Levine, director of marketing for the project, says the studies reveal three Smart House features with the broadest consumer appeal: the entertainment capabilities, including audio and video signals distributed throughout the house; the capability to install sophisticated yet flexible and in-

Participating Firms, Smart House Project

AMP, Inc.
Apple Computer, Inc.
Arco Solar, Inc.
AT&T Technologies, Inc.
Bell-Northern Research Ltd.
Brand-Rex Co.
Broan Manufacturing Co.
Burndy Corp.
Carrier Corp.
Dukane Corp.
DuPont Connector Systems Co.
Emerson Electric Co.
Federal Pacific Electric Co.
General Electric Co.
Honeywell Corp.
I-T-E Electrical Products Co.
Kohler Co.
Landis & Gyr Metering, Inc.
Lennox Corp.
National Semiconductor Corp.
North American Philips Corp.
Northern Telecom Co.
NuTone Division, Scovill, Inc.
Onan Corp.
Pass & Seymour, Inc.
Robertshaw Controls Co.
Schlage Lock Co.
Scott Instruments Corp.
Shell Development Co.
Signetics Corp.
Slater Electric, Inc.
Sola Electric Co.
Solavolt International, Inc.
Southwire Co.
Square D Co.
Systems Control, Inc.
Whirlpool Corp.
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Administration on Aging
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Bell Telephone Co. of Pennsylvania
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Department of Commerce
Edison Electric Institute
Electric Power Research Institute
Gas Research Institute
National Association of Home Builders Auxiliary
National Bureau of Standards
Ontario Hydro
Potomac Electric Power Co.
Professional Builder (magazine)
Southern California Edison Co.
Veterans Administration
Wisconsin Electric Power Co.

Lists are current as of October 1, 1986.

expensive home security systems; and the convenience features, such as flexible switching configurations.

"To get the entertainment capabilities in a house today that you will have in a Smart House requires either expensive custom-wiring or putting a stereo in every room," says Levine. "The flexibility possible with a Smart House security system is something you can't get today without going to a high-end, expensive system. In contrast to most security systems today in which the house is either completely armed or not, Smart House security will let you put individual rooms under alarm.

"The convenience features can be compared to the hand-held remote control for televisions. Before most people had those, they thought, 'I'm not lazy, I can walk to my TV.' But once they have it, just see how long they will walk around the room looking for it if it is misplaced. Our research shows people will react similarly to Smart House conveniences. Once people use them they quickly become addicted to them."

Subordinate to entertainment, security, and convenience, the project's market research indicates home buyers will also be attracted to the energy management capabilities. This reflects a continuing conservation and economy ethic in the consumer marketplace.

Concern for home economy raises the bottom-line question: just how much will being smart cost in a Smart House? "Our best estimate of the cost premium two years from now in the first production models of Smart Houses will be $1500–$2000 for an otherwise $100,000 home" (one slightly more expensive than the average cost of a new home), Levine projects. "But we're not sure that a home buyer would even see that cost premium. The unified wiring should cost less to install, and there may be other offsetting benefits, like utility rebates for load management participation or lower home insurance premiums resulting from greater security and reduced fire potential.

"Four or five years into production, say in the mid 1990s, we think a Smart House could actually break even with the cost of a conventional house," Levine adds. The project's market projections indicate as many as 157,000 Smart House units may be built in the United States and Canada by 1991 if funding, development, and production schedules hold. By 1992 the market could grow to 300,000 new units a year, with sales of Smart House products topping $2 billion. The project has plans for a retrofit version of the technology, which is expected to be on the market by 1990.

The NAHB Smart House may not be the only integrated intelligent home on the market in the 1990s. The Japanese manufacturing and electronics giant, Mitsubishi Corp., plans to begin marketing its integrated Home Automation System in the United States within the next few years (it is already being sold in Japan). Other Japanese consumer electronics firms, including Hitachi Corp., Sharp Corp., Sony Corp., Matsushita Electric Co., Nippon Electric Co., and Toshiba International Corp., are also known to be interested or are working on their own products for the home automation market.

"There is definitely competition in the smart building field," says Barbara Sampson, Smart House project manager. "We may be in a window of opportunity, and if we don't get to market with a viable, reliable, and cost-effective product in the next several years, we will lose the initiative to foreign firms. If we don't succeed, American home builders and home buyers could end up with the Osaka home of the future."

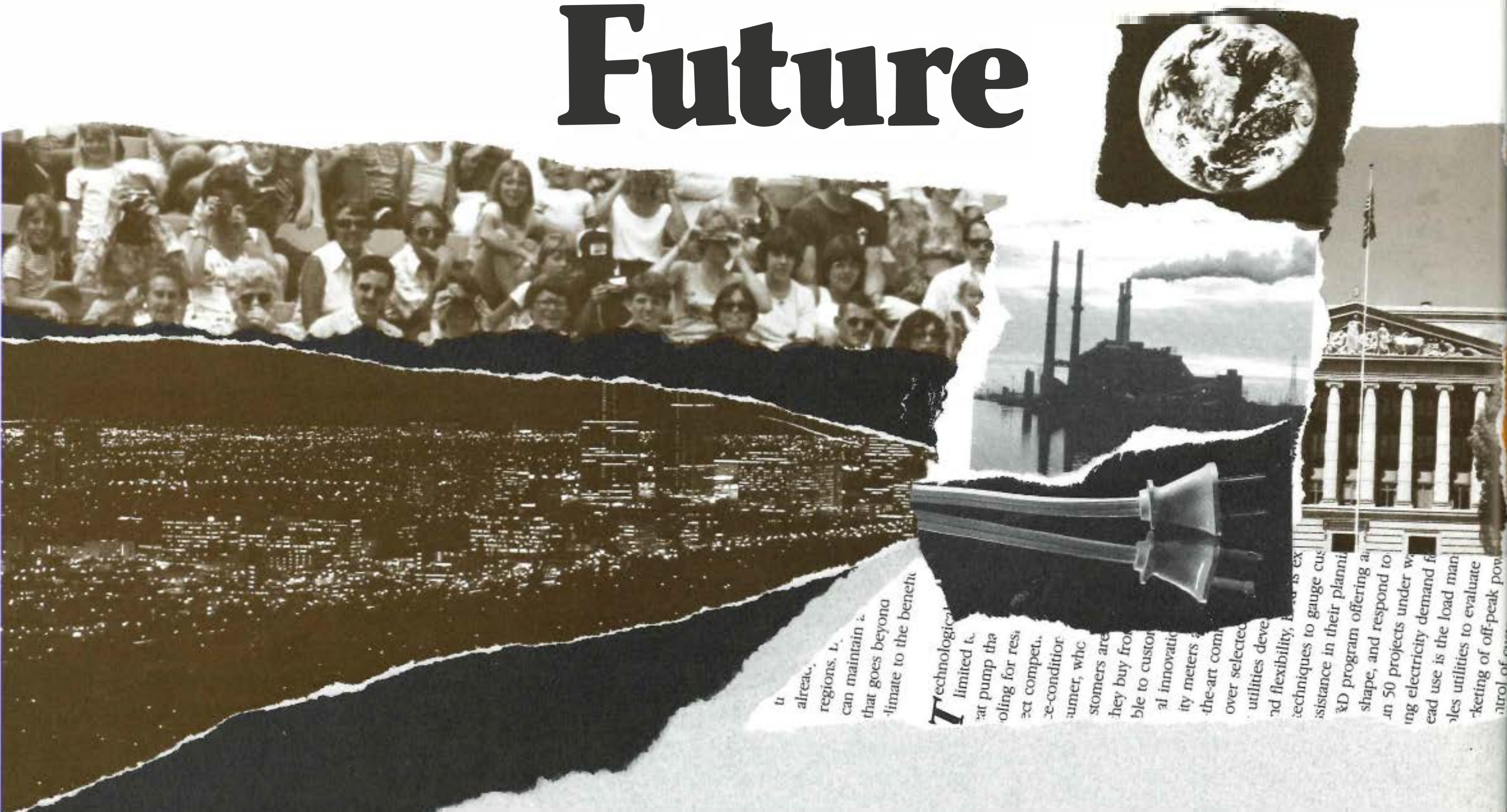
A vision taking form

Exciting visions of the home of the future have long been a part of effective marketing strategies for all manner of new products and services. Artifacts of such visions from decades past seem quaintly amusing today, despite the fact that most of the conveniences heralded as ultramodern in earlier times are now taken for granted. It is not surprising, then, that many of the folks who brought us the time- and labor-saving devices we would rather not do without are working on an even more dazzling array of technology that could become the standard for homes built in the 1990s and well into the twenty-first century. ■

This article was written by Taylor Moore. Technical background information was provided by Veronika Rabl and Orin Zimmerman, Energy Management and Utilization Division.

Adapting Energy Technology to the Future

by Richard W. Zeren



Changes in social values, public policies, and customer expectations are redefining the context of energy research. This is the thrust of an address delivered by EPRI's director of R&D Planning and Evaluation at a recent utility forum discussing technology requirements beyond the year 1995.

Utility system planning was once a relatively straight-forward matter of sizing and selecting new power plants and then weaving a supporting transmission grid among them. Electricity demand grew consistently for 30 years or so. It doubled every 10 years. Not only that, but the cost of electricity went steadily downward.

Today, however, electricity demand is growing slowly, erratically, and unpredictably. The orderly trends of 15 years ago have disappeared, and we are now thoroughly occupied with trying to predict tomorrow's trends.

We still have to plan for the future, of course. But there is more to system planning than its purely technical dimension. The same is true of the R&D that contributes new opportunities to that technical dimension.

The shape of our future

I am going to review some of the R&D avenues and efforts that should produce commercially available technology by 1996. But first, I think it is important to take account of the world that technology will serve. Technology is a tool, after all, and the trick is to make sure we develop the right tools for the jobs we will face. This means acknowledging and internalizing some themes that are shaping the future of electric power service.

U.S. social values and attitudes are the first and probably most important theme—the collective values of our culture and our customers. Next are the customer expectations we try to meet in a better way at a better price. The third theme is change—change around us and within us, both as organizations and as individuals. Taken together, these themes encompass virtually all our national commercial life. Taken separately, they suggest some useful criteria for electric power development.

Social values and attitudes create much of the climate that electric utilities work in. And many new social values have emerged during our professional lifetimes, been expressed, then amplified, and become embedded in the culture. Civil rights, for example, and women's rights come quickly to mind. So do environmental protection and esthetics, conservation, and recycling.

There also are new concerns for fairness and justice, for accountability, for public risks—and for the decisions on who imposes them and who must accept them. We're seeing more insistence on public participation in these and other institutional decisions and on access to power—political and electrical.

Clearly, these values condition the marketplace in which we compete. They shape our customers' expectations of our products and services, the technologies and organizations behind them, and even our whole industry. Social values are calling the turn today, and they'll still be doing it 10 or 100 years from now.

Customer expectations are a more specific theme—needs and tastes in a commercial context. Electricity customers are expecting more, not necessarily more electricity but more recognition of their diverse needs and tastes. We have to think beyond electricity itself to the processes and services that are energized and controlled by electricity and, in some cases, by other energy forms as well.

Electric utility competition most obviously comes from natural gas and oil, but that's not all. Cogeneration of steam and electricity by industrial energy users has come back into fashion. Energy conservation must be counted, too.

The customer's viewpoint

One aspect of successful competition in a given environment is adaptation to that environment. This means thinking beyond all the millions of spinning watthour meters and drawing closer to customers themselves. We have to pay more attention to the first syllables of the word *customer.*

Custom is the expectation nowadays, so products are custom-made, custom-assembled, custom-fit, or even just plain customized. Think of the options and choices in car models. Just a year or two ago and made possible by computers and robotic assembly lines, there were 69,000 permutations of the Ford Motor Co.'s Thunderbird and its various body styles, colors, engines, transmissions, upholsteries, and accessories.

It's no different with electricity itself. That is, it's no different in terms of what utility customers expect—light or heat, music or mechanical drives, refrigeration or computation.

But they expect something else, too, something that has to do more with ourselves as an institution than with our product or service. Our customers want us to be sensitive to social values, to their esthetic, environmental, and safety perceptions. They want us to go for the spirit of the law, not just the letter. They'd like to feel they can trust us. Phrases like *the public trust* and *the service ethic* are old and familiar in the utility industry, but they're taking on a new urgency for the 1990s.

The third important theme is change. Change is part of our environment. Thus we have to make it part of ourselves; that is, we must become specifically conscious of change and use it to our advantage.

Change is always unfamiliar. Sometimes it is disquieting, even anxiety-producing. And it can be risky, too. It has everything in it from danger and loss to security and profit. It often comes at us as a surprise. Only in hindsight does it appear obvious.

In this context, trends are not changes. We get accustomed to trends. They were a steady-state condition in the utility industry for years: the 10-year doubling of demand, scale economies in power plants, and ever-lower kilowatthour prices for electricity. The change was when those trends reversed.

We have to expect change and adapt to it. Better still, we have to anticipate it, even get in front of it, seek it and make it happen. If our attitudes and business practices—and our technology—are flexible, then we can deal with change, whether it's the interdiction of an entire fuel resource or technology or the emergence of a whole new social imperative.

So much for the context of electric power R&D today and in the foreseeable future. But if something under development now is going to be useful in just 10 years, it had better be well on the way to perfection today, not only as a technology but as a commercial offering with potential suppliers. Several areas of R&D qualify in this way. Not all of them are for use by electric utilities, but they will all work on behalf of utilities. I think first of customer expectations and applications—end-use technologies, most of them for industrial electricity productivity but some for individual loads.

The shape of our technologies

As we are recognizing today, customers will be number one in 1996, and we will be working hard to meet their needs. Technology will play a role, and we can already detect a couple of key trends: improved efficiency in existing end uses of electricity and the propagation of completely new uses, some of them as yet unknown. R&D is under way to encourage both.

Better efficiency is important because it keeps electricity price-competitive, keeps our customers with us. Two well-advanced developments are illustrative. Heat pumps for space conditioning are common now, but by 1996 new versions will be 20–40% more efficient. Likewise, energy management systems for entire buildings are with us today but haven't nearly exhausted their potential for integrated load leveling, air conditioning, and heat or cool storage. Because air conditioning alone can account for 20–40% of a utility's peak demand, these systems will mean real control of peaks by customers, especially as the commercial sector of the economy grows.

Then there are brand-new uses of electricity in manufacturing. We're seeing the leading edge of these right now. In a few instances, they're helping to revitalize entire industries. Here the point is productivity—blending energy, materials, labor, capital, and management in whatever way will achieve the lowest overall cost. An electricity-intensive process may make a whole operation less capital-intensive, cut material waste or manufacturing time, or reduce warranty claims.

One example is the plasma-fired cupola, used for melting metal in foundries. Electric arcs superheat gas to much higher temperatures, enabling both better process control and use of a wider range of scrap metal. Early applications are showing hot metal costs 15–30% lower than before.

Other new developments in manufacturing depend specifically on electricity—robots and information processing systems, for example. These aren't big power users, but they illustrate electricity's high form value, in this case its precision, which yields speed and material savings in manufacturing.

Demand-side management encompasses all the efforts directed to shaping utility load, customer by customer, industry by industry, day to day, and season to season. New forecasting tools are one approach; they help us understand what specific programs make the best sense for both utility and customer. New devices measure individual electricity uses and reveal their effects on utility networks. With these developments, we will know customers' needs better and be able to shape electric bills to our mutual advantage.

Moreover, when we understand our customers well enough, we may find that new electricity products—as distinguished from electricity uses—are advantageous. Some utilities routinely differentiate electricity cost (and price) by time of day. The next step will be to differentiate cost by level of reliability and quality. We have yet to learn what these virtues are worth, but clearly, a steel mill superintendent, for instance, isn't nearly as concerned about waveshape purity as is an investment banker, who needs that quality to keep his communications and computers—and his business—alive.

The delivery system

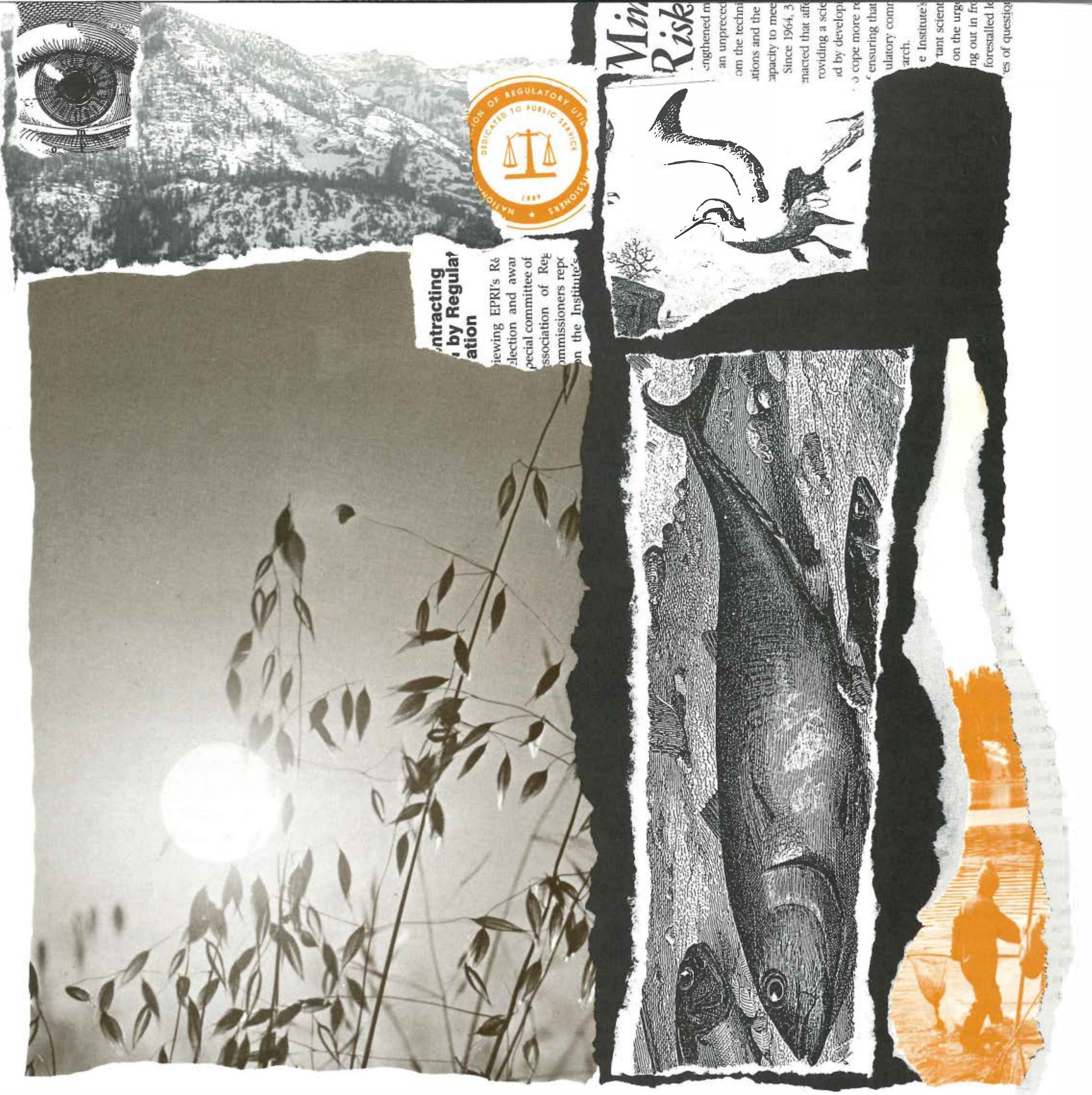
The fundamental supply of kilowatthours—not to mention variable electricity reliability and cleanliness—hinges on delivery, especially on utility distribution networks (which carry power at less than 69 kV).

Distribution networks are more extensive than transmission systems, and they represent a greater investment. Distribution is the source of more customer problems, too, whether caused by lightning or by a careless backhoe operator. Shifting populations and patterns of power use suggest that distribution will attract the bulk of the utility industry's capital investment for the next 10 years or so. With new technology we can multiply the value of this investment, making supply more reliable and service more rapid and precise.

Automation is the pervasive concept for cost-effective operation of distribution networks. Key examples are computerized monitoring and measurement apparatus for reliable substation control and system dispatch, fault detection, and expedited repair. All these functions are coming together now in an EPRI-sponsored demonstration that will include more than 5000 data and control points on the Carolina Power & Light Co. system. From this will come the design and experience blueprint for other utilities to use in building and operating similar systems and to save money by doing so.

New tools for utility field crews are another R&D category—tools and techniques for faster and safer installation, maintenance, and repair of anything from a switchyard to a substation to a watthour meter. Pavement cutters, remote manipulators for repairing hot lines, self-guided boring machines, and splicing aids are all examples of advances that make a utility's labor investment more productive.

A power delivery system is made up of millions of little pieces—long-lived switches, breakers, arresters, insulators, and nuts and bolts. By 1995 we'll have



Values of U.S. society are changing

The assertion of popular rights and the recognition of environmental stewardship are involving citizens in choices of how technology is developed and by whom, where it is used, and how. New technology for electric utilities will use fuels more efficiently in downsized plants, reduce combustion emissions, and cut losses in delivery systems.

significant improvements in a lot more of those pieces, from high tech to low. Transformer cores of an amorphous iron alloy are one example; their core losses are 70% less than losses in conventional cores, saving the equivalent of some 16 kWh per year for every kVA of transformer capacity. The figure for one unit is small, but the saving is significant when extrapolated over the years and over the nation. Tougher pole line insulators are another example. They are simple, passive components, but made of low-cost polymer concrete, they will last longer in inventory, in handling, and in use.

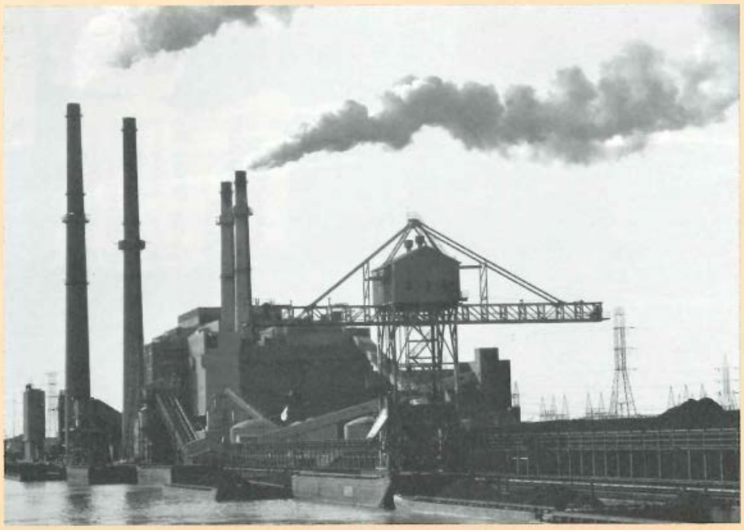
Utilities will spend very selectively on high-voltage transmission systems, augmenting today's capacity where needed to handle imported power, power from new plants or third-party generators, or power being wheeled across service territories or regions. We'll stretch systems as much as we can and add new links only where we must.

Stretching means using transmission rights-of-way more efficiently, moving power at higher voltages—called upgrading—and stringing lines closer together—called compacting. As we demand more from systems, operating them closer to their limits, we will need a better understanding of what's going on: more instrumentation, more measurement, faster analysis, more control—all in the direction of automation.

We'll build new transmission links where necessary. Dc entails lower electrical losses and permits finer control. New analytic techniques are giving us a better understanding of how dc can coexist in the already extensive ac grid. Thus, with development of cheaper converters and new breakers, multiterminal systems—that is, dc systems with several interconnections to ac networks—are becoming feasible.

Already, EPRI-developed software is in use for optimizing the design of transmission towers, poles, and lines. The programs make up an electronic handbook that is always state-of-the-art, with the latest physics, plenty of good empir-

The Shape of Our Technology Dependence



Is there really a place for new technology in an electricity future dominated by social values, customer expectations, and change? The answer is yes, but because the demands on our business are different, so are our technology needs.

Beyond the general social themes and their implications, we must also acknowledge three characteristics of electric utilities that are especially bound up with technology—subject to its influence. Utilities are financially and environmentally sensitive. And they are resource sensitive.

Utilities are financially sensitive because, collectively, they make up the most capital-intensive industry in the world. Even with only low growth, we have to maintain and upgrade very large, complex, and widespread capital plant. Eventually, one way or another, we must replace it. We need hardware options that shelter us from fluctuations in interest rates, customer demand, or regulatory treatment. This is a place for new technology.

Next, utilities are environment sensitive. The pervasive effects of the reactor accident at Chernobyl remind us of this. But, completely apart from what anyone says about nuclear power, our industry emits more waste into the atmosphere than any other. We are defined as the largest single atmospheric polluter. There is dispute about the effects, but we must deal with the reality, and this includes the perception that utilities are somehow dangerous or uncaring. Waste disposal—all kinds—is a place for new technology.

Finally, utilities are resource sensitive. Their cost structures have been battered by fuel prices for the last 10 years, although these have eased just recently. We don't see a problem in the availability of fuel for 1996, but price could be a different matter. There's always the surprise of an OPEC, a TMI, or a Chernobyl. Utilities must be prepared to cope. The requisite flexibility means alternative processes and machinery for fuel use. These also mean needs and opportunities for new technology. □

ical data, and new and fast calculational techniques. But it's the concept that's so powerful. By 1996 we ought to have comparable software for substation and plant design and probably for dozens of other areas.

Power generation

In 1996 most of our electricity will be generated by the same plants we own today. Still, in important ways they will have to be different plants—that is, run differently—if electricity is to maintain its competitive edge.

We're going to be into power-plant geriatrics. Diagnostic techniques and monitoring instrumentation will be key, just as they are in medicine, along with the information management systems that tie them together in functional packages—again, just as in medicine.

Today's instrumentation portfolio will continue to grow. The leaders among us will have their own in-plant expert systems to help run plants well, anticipating and preventing outages and managing maintenance.

We will use a select few new generating technologies in the 1990s, important because they will meet utility requirements in ways that today's power plant designs don't. For one thing, they will entail less financial exposure for the utility. That is, they will be cost-effective in smaller sizes. They'll be modular, too—largely factory-built and shipped by barge or train. Such plants will be easy and fast to erect, and they will be expandable simply by the addition of identical modules.

From a technical standpoint, the new units will be inherently cleaner running. And they'll be fuel-flexible; that is, they'll be tolerant of a range of fuel quality, maybe even of different fuel types.

As for the specific technologies for 1996 and thereafter, the combustion turbine comes first. It will be a hotter, much higher-reliability machine than today, designed that way from the ground up and proof-tested under EPRI auspices in its first utility application. Such a program should give other utilities the benefits of authentic operating data and, where needed, design improvement. In combined-cycle configuration (with a heat recovery steam generator and steam turbine), this turbine will be usable for baseload if gas and oil prices stay down. It will burn natural gas, distillate, or fuel oil.

A second candidate is coal gasification with combined cycles. It offers financial flexibility via phased construction. Begin with an inexpensive combustion turbine, then add the steam cycle fired by oil or gas. Finally, if gas and oil prices rise, add a coal gasifier. The integrated gasification–combined-cycle technology is already being demonstrated at the Cool Water plant in southern California, with excellent performance and startlingly low stack emissions during extensive runs with both low-sulfur (0.5%) coal from Utah and high-sulfur (3%) coal from Illinois.

Even if other utilities don't build plants of this type, Cool Water is providing a way out from under high gas or oil prices. It is thus creating a great range of business flexibility, reducing the regulatory and financial risks of combustion turbines and combined cycles.

Atmospheric fluidized-bed combustion (AFBC) is a third new power technology, and actually a relatively small departure from the utility industry's familiar pulverized-coal plant. An air-suspended bed of ground coal and limestone burns at a lower temperature than pulverized coal. Chemical reactions between the coal and the limestone capture sulfur from the combustion gases, and the lower temperature inhibits nitrogen oxide (NO_x) formation. AFBC is economical at the 200-MW scale, and although it isn't modular per se, it is amenable to factory fabrication in larger sections than is a comparable pulverized-coal unit.

Fluidized beds can be retrofit to existing boilers in some instances, increasing a utility's fuel flexibility while avoiding the usual add-on complexity and cost of scrubbers and low-NO_x burners to reduce emissions. It may also recapture some of a power plant's rating lost by an earlier switch to a lower-sulfur and lower-Btu fuel.

A less certain future

Several other advanced technologies may or may not be candidates for utility use by 1996. Four come to mind: the fuel cell, the advanced light water reactor (LWR), energy storage (compressed air and batteries), and photovoltaics.

The fuel cell is difficult to predict. It offers so many incentives: easy siting, fast construction, clean, quiet operation, and excellent dynamic behavior on-line. But its capital cost is high compared with that of the combustion turbine. Also, there's an awkward cost transition between R&D and commercialization. An automated assembly plant would bring the unit cost down, but the manufacturer needs orders to justify that investment. So far, high cost is keeping the order book empty.

The advanced LWR remains an important strategic goal, but bookings of 800–1000-MW plants of any kind seem unlikely by 1996. Also, none of the small LWR designs will have been adequately developed for installation to begin at that time. However, to gain fuel flexibility across the industry, to exploit a domestic fuel resource, and eventually to meet environmental problems caused by burning fossil fuels, we have to continue R&D toward a nuclear power plant that can win the confidence of both utility management and the community at large.

Energy storage may be a useful option, especially as commercial electricity loads grow and cause peak demands well above average levels. When the ratio of average to peak load (known as load factor) thus declines, storage is an alternative to peak generating units that lie idle much of the time. Storage also has appeal where minimum loading is a periodic problem. When customer load falls below the level at which generating units can run, surplus energy can be diverted to storage.

So far, compressed-air energy storage

Expectations of U.S. consumers are growing

Innovation of every kind encourages ever-wider choice and stimulates competition among suppliers of goods and services. New technology for electricity use will increase its versatility and productivity in industry, commerce, and the home, and even tailor its quality and reliability to customer preferences.

(CAES) is furthest along, with several utility planning studies done and Alabama Electric Cooperative committed to a 50-MW (10-h) facility. The storage cavern, to be leached out of a salt dome, should be equipped and ready to operate in 1989. Expected to come in at a capital cost of less than $600/kW, CAES appears to be economically feasible in small sizes, but its benefits are very site- and system-specific.

Battery energy storage can be sited more flexibly, and batteries are attractive because of the speed with which they can be taken on- or off-line, a simple matter of switching. But most advanced designs must overcome technical obstacles before they will be ready for use. Then, as with the fuel cell, a chicken-and-egg problem of capital cost and production volume is likely to make commercialization problematic.

New lead-acid battery designs are the closest to feasibility right now. Interestingly, they are a beneficiary of environmental awareness: lead prices are attractive because there no longer are large sales to the paint and gasoline industries. Battery material costs and cycling capabilities still are trade-offs, but Southern California Edison Co. is putting a 10-MW (5-h) load-leveling plant on-line in about a year. It will use lead-acid batteries that are half again more efficient in energy per pound of battery material than batteries of only 10 years ago.

Photovoltaics is not economical for bulk power generation today, and the technology's future depends not only on further development but also on the price of alternative generation. The cost target for EPRI's photovoltaic research at Stanford University last year looked competitive (it was at the margin of electricity from oil and coal plants in the Southwest) and the program set a record for energy conversion efficiency with silicon solar cells—27.5%. With fossil fuel prices now down so sharply, the probable market has been delayed; but there is definitely something here, and our research continues. We're already moving to manufacturing processes that can bring the cost down.

The opportunity to adapt

I've described a number of technology advances that should be available and in use by 1996. They're all being developed now, and for the most part, they're well on track. I've also tried to suggest why these advances are important.

Indeed, the *why* for a lot of R&D isn't the certainty that we'll need a particular new widget. Almost as often, the *why* is that we're not sure. We're hedging against the unforeseeable by creating options. Some of EPRI's hardware options, therefore, are for different eventualities. And some of our software—planning tools, for instance—is for sorting out those eventualities.

Some of the events that lie ahead may hinder electric power development. But the worst thing would be for them to distract us, because I believe most of the future will help us. The reason is simply that electricity is such a convenient form of energy with which to make so many things happen.

On the upside of uncertainty, people are incredibly innovative and adaptable—key attributes of our species. We'll be changing in ways we can't foresee right now. We must, because the world around us is changing.

The world was changing 14 years ago when EPRI got started. Some electric utility leaders with great vision recognized the imperative of creating the technical and scientific destiny of their industry. They undertook a major innovation in organizing EPRI as a cooperative, member-supported research endeavor.

EPRI's members today are the preponderant industry force, even more so than in 1972. And EPRI is an integral part of that force, producing measurable R&D results that our members use today. We have put in place a scientific base to understand and deal with many issues—resources, processes, the environment, health, and safety. This is a necessary capability for planning and making decisions for the 1990s. It's necessary but it's no longer sufficient.

Back in 1972 the issues were mostly technical and so, of course, were the solutions. How do you double the size of the business, and the plant to handle it, every 10 years? Those were technical questions calling for technical answers.

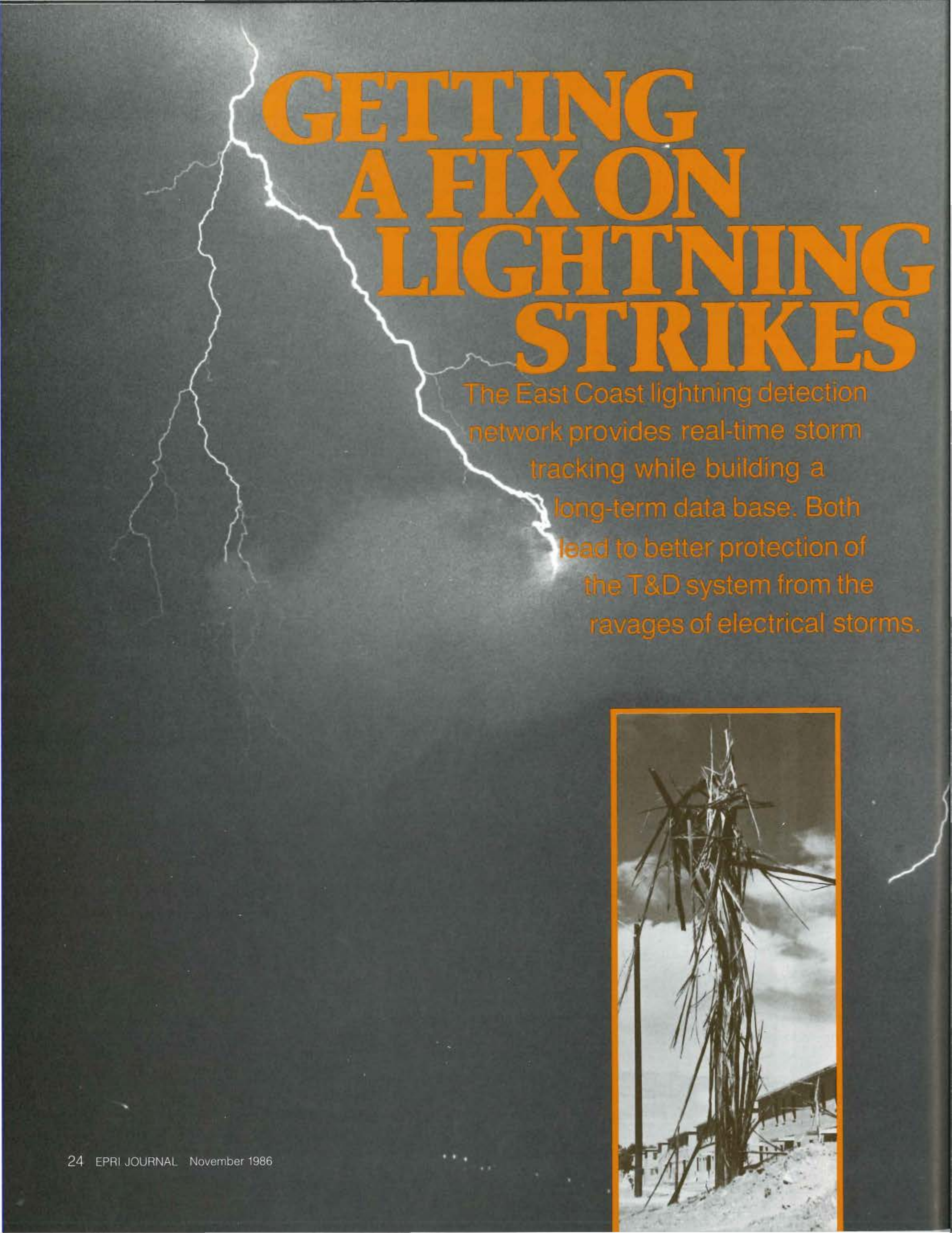
Today's issues are different. Not just technical problems, but problems in marketing, human resources, public relations, finance—all the areas of running a business. But there is still a technological dimension to all these problems that we can't ignore.

The challenge of the next 10 years is every bit as difficult as that of the last 14. We'll not be in charge of the outside events that are bound to happen. Be we are in charge of how we respond to them.

Technology is part of that response, as we conform to new social values, meet new customer expectations, adapt to change—and even lead it when appropriate. In the process, we'll improve our own financial well-being, our resource flexibility, and everyone's environmental health.

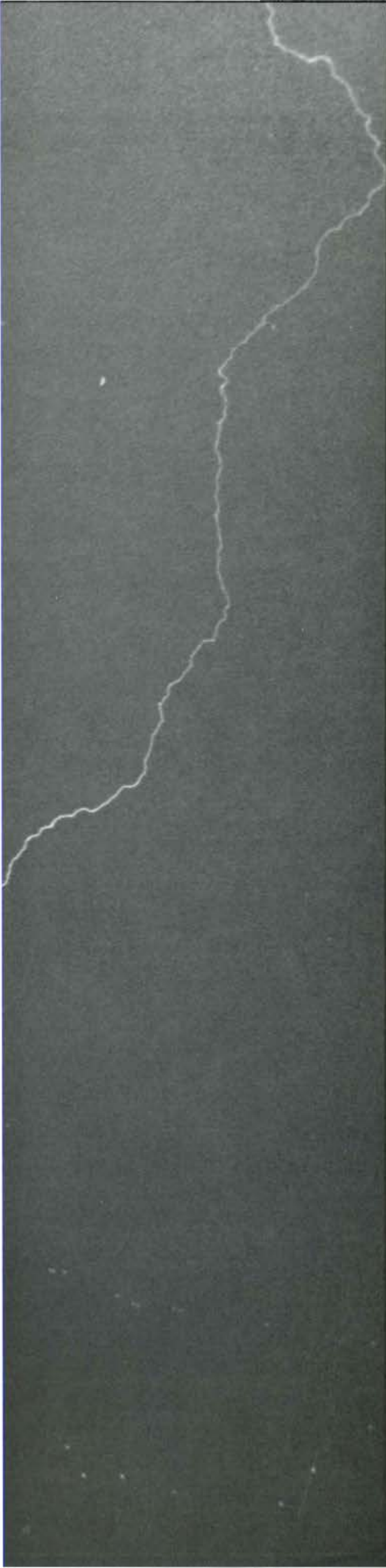
Altogether, these are our responsibilities and our opportunities. We mustn't let go of them. What's needed is to continue—even increase—our active pursuit of technology. It's our lever on the future. ■

This article was adapted from a speech by Richard Zeren, Planning and Evaluation Division, to the System Planning Committee of the Edison Electric Institute.



GETTING A FIX ON LIGHTNING STRIKES

The East Coast lightning detection network provides real-time storm tracking while building a long-term data base. Both lead to better protection of the T&D system from the ravages of electrical storms.



During an average year in the United States lightning causes an estimated $50 million in damage and restoration expense to power lines, transformers, and other electric utility equipment. With more than a quarter-million miles of metal transmission and distribution wires crisscrossing the nation, some of this lightning damage is inevitable. But some of it can be prevented, and much of the damage that does occur could be repaired more quickly and safely if utilities had a better understanding of where and when lightning is most likely to strike.

Ten utilities on the East Coast are learning just how useful good information on lightning can be through their participation in the lightning detection network (LDN). LDN was originally designed to gather long-term data that could be used to map the frequency, location, and severity of lightning throughout the United States. Such a lightning atlas will help utilities refine their decisions on how much surge protection equipment to buy and where to install it. But because lightning activity appears to vary in 10–12-year cycles—perhaps related to sunspot cycles of similar duration—at least a dozen years of data will be needed to build a statistically valid and useful data base.

In the near term, however, LDN is being used by participating utilities as a storm tracking service. By accessing the LDN computer, utilities can continuously monitor the location of lightning as it approaches and passes through an area. This knowledge in turn helps them decide when and where to mobilize repair crews before the storm arrives. Those utilities already benefiting from this service find that it pays for itself very quickly in more-efficient use of manpower and in more-rapid restoration of customer service following lightning-related outages.

Mapping the thunderbolts

LDN is gathering far more detailed and useful data on lightning than was possible in the past. Utilities have traditionally based their surge protection strategies on rough counts of the number of lightning flashes, made through extrapolation from tallies of thunderstorm frequency, from the number of days in which thunder is heard, or from data gathered by simple flash counters. But the number of flashes is only part of what utilities want to know, because lightning events vary widely in several important ways.

For instance, only some lightning bolts strike the earth; others occur within or between clouds. Some flashes contain a dozen or more strokes, while others are single bursts of energy. Their peak current varies widely, and some flashes are positively charged, while others have negative polarity. All these characteristics influence the damage a flash may cause if it strikes utility equipment. Affordable techniques for monitoring these properties were not widely available in the past. LDN is a cost-effective monitoring option, and that's why it holds such promise for utilities.

The techniques used in LDN were first developed in the late 1970s. Some of the earliest applications were in the western states (by the Bureau of Land Management and the U.S. Forest Service) to aid in forest and range fire detection. In 1979 Tampa Electric Co. installed a lightning detection system as part of a U.S. Department of Energy–sponsored study on the effects of lightning on distribution lines. By 1983 the National Science Foundation and the National Aeronautics and Space Administration had jointly funded the installation of eight monitoring stations along the East Coast.

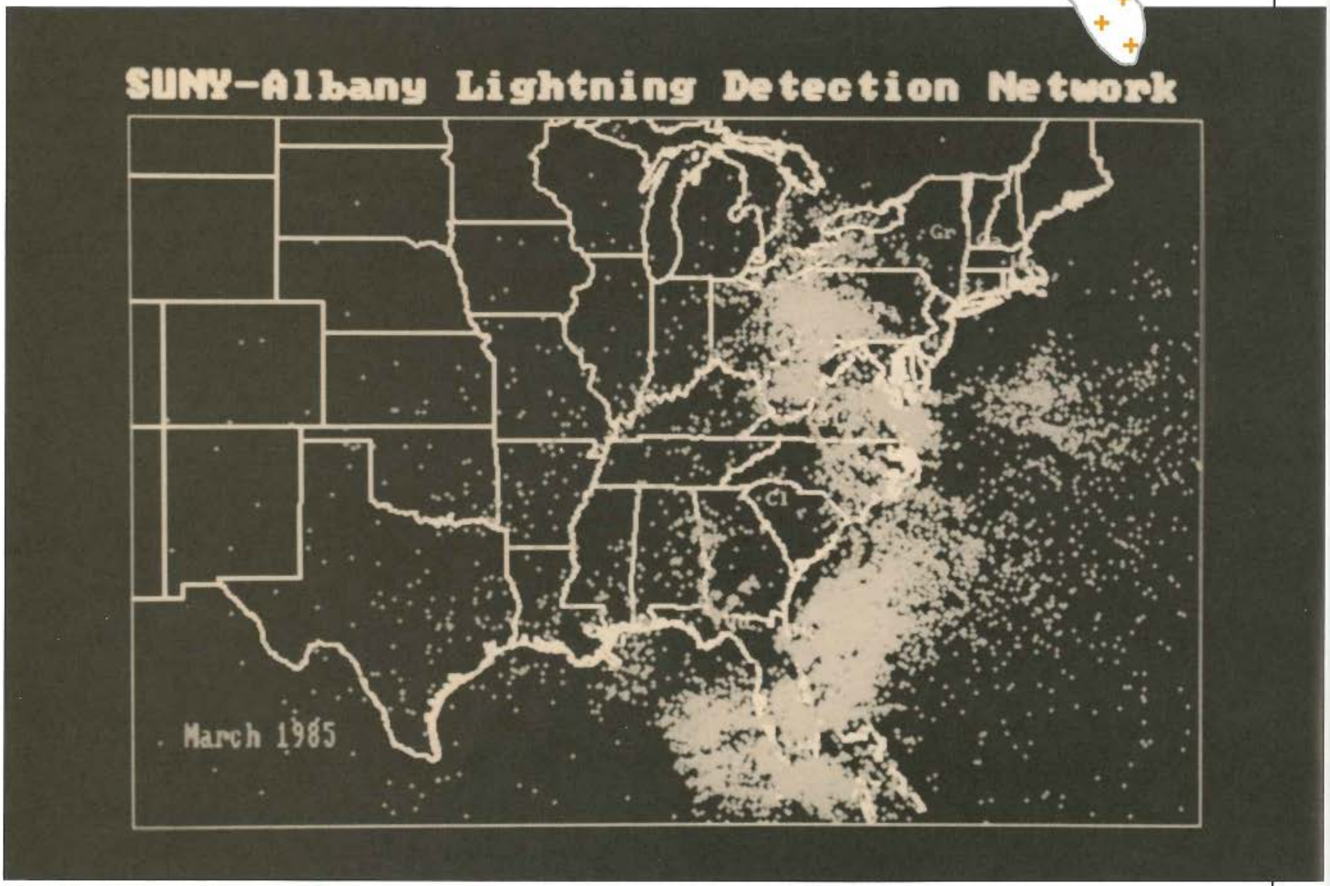
Recognizing the potential value of such a network to utilities, EPRI funded a program to expand the system. By mid 1986 26 stations were operating, covering the territory east of a line from Erie, Pennsylvania, to Mobile, Alabama. Within the next few years, the Institute plans to add enough new stations to monitor everything east of the Mississippi River. Options are being investigated for gathering similar data west of the Mississippi.

The Monitoring Network

Twenty-six monitoring stations, each with a nominal range of 400 km, enable the lightning detection network to monitor lightning throughout an area east of a line extending from Erie, Pennsylvania, to Mobile, Alabama. Each monitoring station contains a small amount of electronics hardware and several antennas that sense electromagnetic waves propagated by lightning. Signals from the monitoring stations are continuously transmitted through dedicated communication lines to a network control and data processing center at the State University of New York at Albany. The Albany center instantaneously calculates flash locations and sends this information to subscribers to the storm tracking service. Additional lightning data are archived at Albany for later compilation and analysis.

Monitoring station

Network control center



Storm display on screen

Each station consists of several special antennas and a modest amount of electronics hardware compact enough to fit in a small trailer. The stations, each with a nominal range of about 400 km, are linked by dedicated communication lines to a data processing center at the State University of New York at Albany (SUNYA). According to Richard Orville, who directs LDN, the Albany center has recorded about 10 million lightning flashes since June of 1983, archiving the information for later analysis and compilation.

LDN stations work by sensing the electromagnetic waves generated by lightning. The SUNYA computer polls all the stations every 10 s and uses a standard time signal to synchronize the data arriving from the various monitoring sites. It recognizes the difference in waveforms between intracloud and cloud-to-earth flashes and records only the latter. When two or more stations sense a flash within a programmed time interval (6 ms) the computer assumes that they are sensing the same event. It then triangulates the signals to geographically locate the lightning within a few kilometers anywhere in the network. By counting additional closely spaced signals from the same location, LDN can determine how many strokes occur in a given flash. Magnetic field strengths are archived by the computer and used later with statistical correlation techniques to estimate the peak currents of lightning events.

The system is not perfectly accurate. Some flashes escape detection because their waveshapes are different from those the stations are programmed to measure. Other flashes may be so weak that their field strength falls below the monitoring threshold. And some return strokes may go uncounted if they repeat in intervals of less than 6 ms. Despite these weaknesses, the network is about 80% accurate and provides far more useful information than was available in the past.

Enough data have been gathered and analyzed at SUNYA that preliminary flash density maps have already been produced for some portions of the network. According to Herbert Songster, who manages EPRI's lightning research, "As more data are collected over the coming decade, reflecting the annual variation in lightning activity, these maps will become increasingly accurate. The improved accuracy of the data on lightning characteristics and location will enable surge protection engineers to design and apply more-effective systems for protecting utility equipment."

Protecting utility equipment

Utilities cannot prevent lightning from striking their equipment, but they can install protective devices that will conduct the energy to the earth rather than allow it to pass through insulators, transformers, circuit breakers, and other devices. In principle then, most of these protective devices are like the lightning rods found on many buildings.

Most transmission lines and some distribution lines in high-lightning areas are protected by shield wires, which are strung above the energized line. As with lightning rods, shield wires are positioned to intercept lightning bolts and shunt the current to the ground. They do their job well but not with complete success. Lightning sometimes misses the shield wire and hits the energized line instead, causing power surges that can destroy vulnerable components. Even if the lightning does hit the shield wire it may cause enough of a voltage differential for the energy to spark across to the energized conductors.

To protect substations, utilities often erect lightning masts—tall metal poles that conduct the energy from a lightning flash directly to the earth. They also protect substations and distribution transformers with surge arresters. When voltage rises to a predetermined point above normal levels, the resistance in surge arresters falls suddenly, conducting the current to earth.

Utilities cannot afford to install the highest quality surge arresters and shield wires everywhere that lightning might strike a system. That is why the statistical data on lightning density and severity being compiled by LDN will help utilities make more-informed decisions. "For instance," says Songster, "flash density maps may show utilities that they are spending too much on lightning protection equipment in some districts and not enough in others." If most of the flashes in a given area contain only one or two strokes of relatively low strength, less-expensive surge arresters may be sufficient. On the other hand, heavy-duty arresters would be called for in an area known to experience a high frequency of strong, multistroke lightning.

The polarity of lightning in an area may also affect the optimal surge protection strategy. It was previously thought that 90% or more of all lightning was negatively charged. LDN data are showing, however, that although about 90% of summer lightning is in fact negatively charged, most winter lightning is positively charged. Utilities with frequent winter lightning can use this information to select the best lightning protection equipment for their conditions.

On-line monitoring

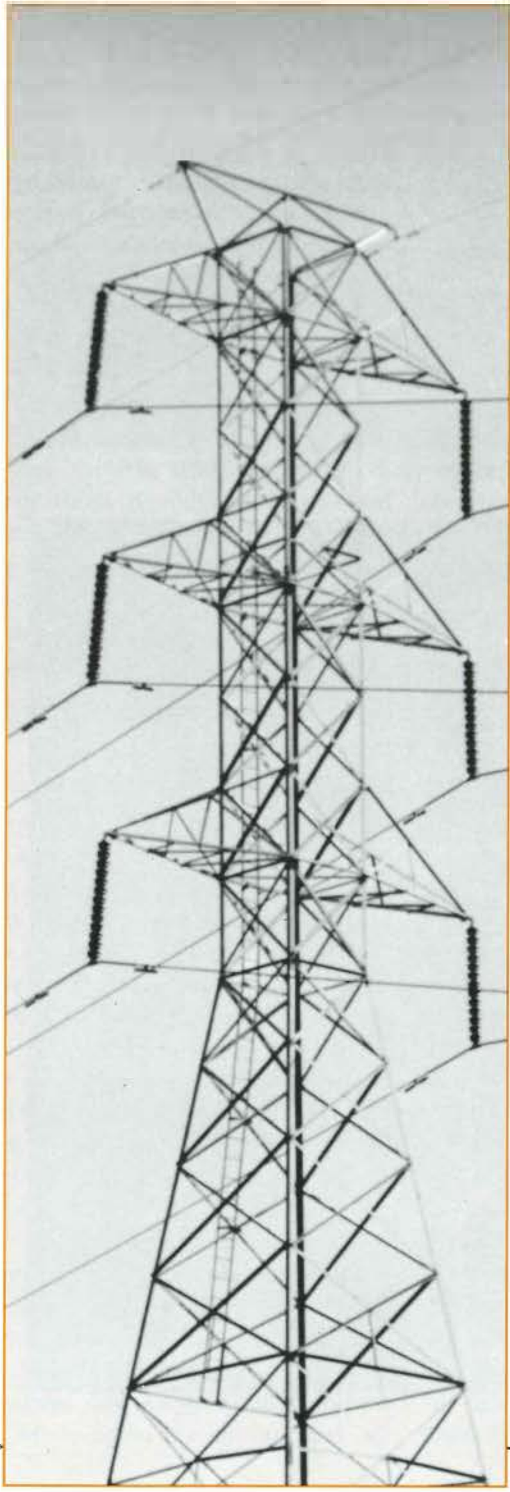
In addition to the improvements in system engineering that the LDN mapping data will make possible, the network's storm tracking service can improve operational performance as well. With an investment of about $10,000 in computer equipment and the necessary software, any utility within the monitored territory can set itself up to access the network, either through a 24-hour dedicated AT&T line or by an on-demand 2400-baud phone hookup. The annual cost to an EPRI member utility for the dedicated line, software updates, and continuous data access is about $6000.

The system displays lightning events within a second of their occurrence on a color video monitor adjusted by the operator to map any geographic area from a fraction of the utility's service territory to the entire multistate range of the net-

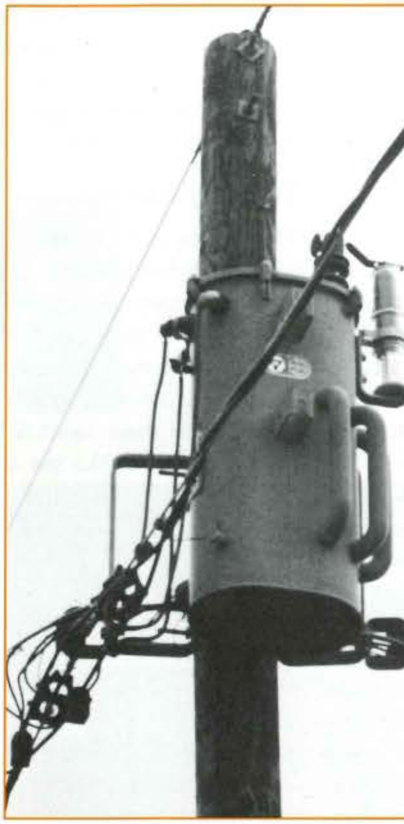
Protecting Equipment in the Field

Utilities use shield wires strung above transmission lines and surge arrestors mounted on transformers and substations to shunt energy from lightning strikes to the ground before it can damage vulnerable equipment. Better data on lightning flash density will help utilities to make more-cost-effective siting and sizing of protective equipment.

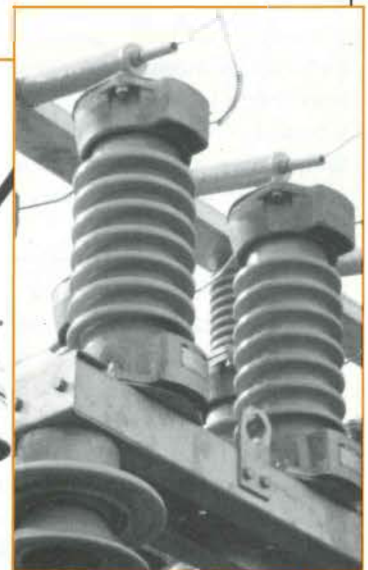
Shield wires (at top)



Surge arrestor on transformer



Surge arrestors



Mapping Flash Density

In the past, measures of thunderstorm frequency were used as surrogates for more-precise lightning counts. Today, the lightning detection network tallies flashes directly. The map shows areas having the same number of flashes per square kilometer in 1985. Because lightning activity varies from year to year, about a decade of data collection will be needed before such maps can be considered statistically valid.

1985 Flash Density (flashes/km^2)

1
2
3
4
5

work. The system engineer who wants to know when an approaching storm front reaches the borders of his service territory can either watch the screen or set the monitor to activate a buzzer when the first flash of lightning occurs within a preselected geographic area.

When a lightning flash occurs, it is depicted on the video monitor as a colored dot. After the dot has appeared on the screen for a time period specified by the system user, it changes color, and does so again at regular intervals. This multihued pointillist image of the storm is not just for show. It allows the viewer to judge how fast a storm is moving and to determine for any given area if the lightning is over or if more is on the way.

Utility experience

Ten utilities had subscribed to the LDN storm tracking service as of August 1986. One of the first companies to sign up was Baltimore Gas and Electric Co. Andrew Dodge, associate engineer in electric system operations, explains that most thunderstorms in the BG&E service territory appear in the late afternoon or early evening. But the repair crews end their shifts by 3:30 in the afternoon. In the past the decision to keep crews overtime when a storm was approaching was based on local weather forecasts and precipitation data. No information on lightning activity was available. With the real-time information provided by LDN, Dodge says his utility can make a far more informed judgment on manpower needs.

"LDN allows us to have crews strategically mobilized before a storm hits our service territory, so that any damage that does occur will be repaired as quickly as possible," he says. Equally important, the monitoring network helps the utility decide when crews will not be needed. "Access to LDN costs us about $6000 a year. We used to spend that much in holding crews overtime unnecessarily in one or two storms. So the network is definitely a worthwhile investment for us, not even counting the benefits we obtain in restoring service more quickly after lightning-related damage." Dodge expects that more utilities will subscribe to the service, based on a number of calls he has received in recent months from interested companies that are not yet participating.

Robert Filipovits, a senior engineer in distribution research and reliability for Pennsylvania Power & Light Co., echoes Dodge's sentiments. "When you're in an emergency situation, all the information you can gather and assess makes for more-intelligent decision making."

Like most utilities, PP&L obtains its weather data from a number of sources, including the National Weather Service. Filipovits explains that his utility uses LDN to augment other reports. "In the past we had to assume that the weather reports were correct when they told us that a major storm carrying lots of wind, rain, and lightning was on the way. Now we can go to the lightning detection network and may find that there's really no lightning coming with the storm. Or maybe there is more than we were led to believe. Either way, that is very useful information."

The utility also plans to use LDN data in its effort to model storm behavior and restoration work. "We find that there are patterns in the kind of trouble cases we experience in different kinds of storms. We are studying these patterns now and using them to develop models to help us predict the kind of damage we can expect from incoming storms."

One unexpected use of LDN comes from the high-voltage transmission crews at PP&L, who are at considerable risk if a lightning storm arrives while they are working on the lines. They now contact the operations center before starting any line maintenance to learn if any lightning is expected in the area. "If we know the line crews are out in the field and we see lightning coming into the area, we notify them immediately so they can stop any potentially dangerous work. This kind of information can save lives," stresses Filipovits, "and that makes the lightning detection network all the more valuable."

An ongoing effort

Unlike many problems facing utilities, there is no ultimate cure for lightning. It will always be there, inevitably damaging a certain amount of utility equipment and causing some service interruptions every year. "We can't stop it," comments Songster, "but we can at least be ready for it." Getting ready will take years of data collection to build accurate maps of lightning distribution. But the payoff in refined protection strategies and reduced damage should be well worth the effort. In the meantime, the storm tracking service provided by the detection network will vastly improve the safety and speed with which utilities cope with the random destruction caused by those uncontrollable flashes from the sky. ■

Further reading

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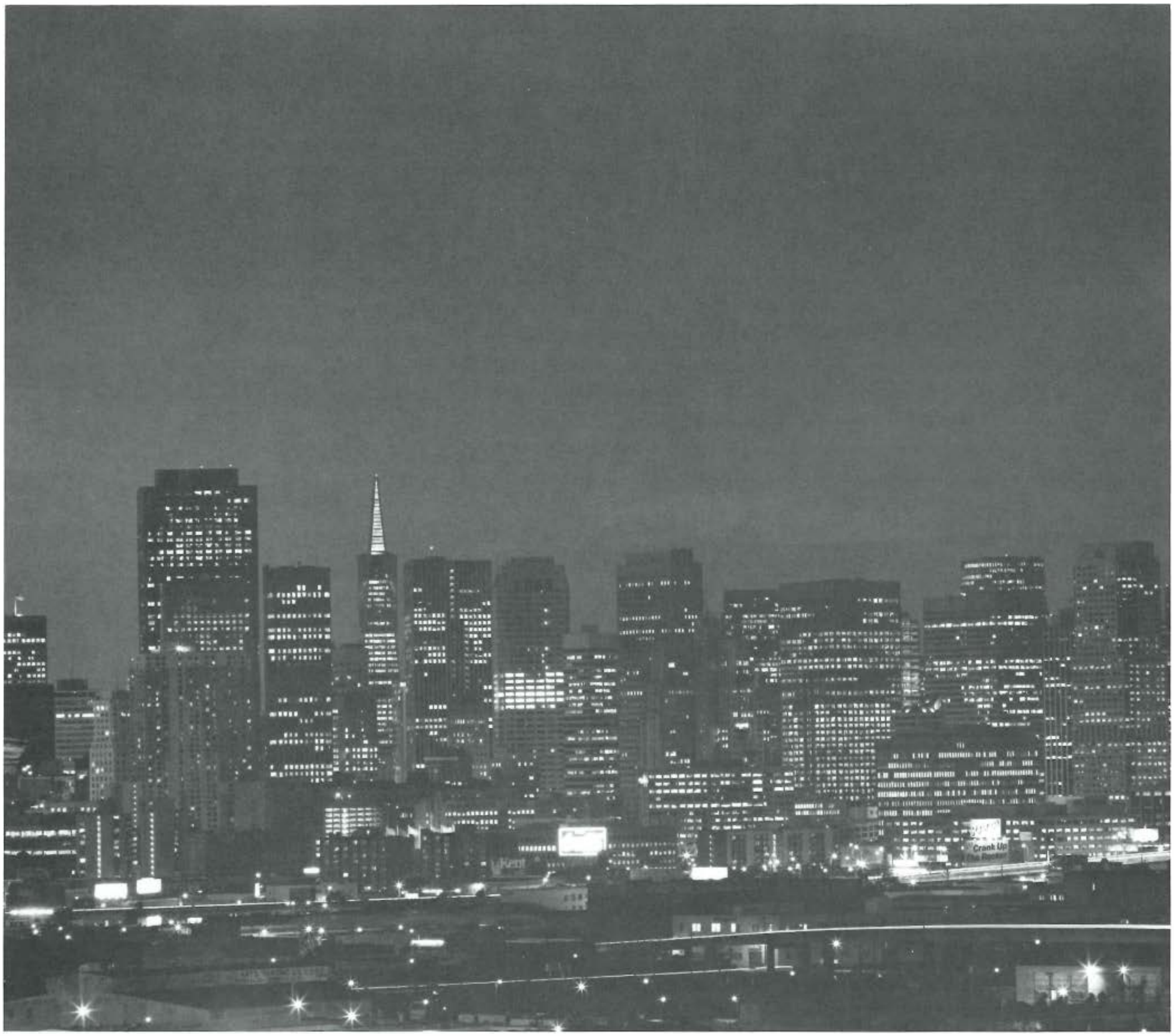
This article was written by Michael Shepard. Technical background information was provided by Herbert Songster, Electrical Systems Division.

SYSTEM RELIABILITY
SEEING THE WHOLE PICTURE



Could changes in the utility operating environment over the next decade threaten the preeminence of U.S. electrical system reliability? New models emphasizing the interplay of generation and transmission reliability should provide the answer.

The electric power system of the United States ranks among man's largest-scale projects." So begins *The National Electric Reliability Study* by the U.S. Department of Energy, tacitly acknowledging that the immense scope and complexity of the North American electric power system is never more evident than when one is trying to assess how well it will function when pushed to the limit.

Any study of electric system reliability deals with those limits directly, asking such questions as, How often will not enough electricity be available to meet demand? How many customers will be affected by each outage? And for how long? The short answer to these questions is, no one knows for sure. Concern is rising, however, that the world-renowned reliability of America's electric power network faces its most serious threat in decades.

This point was brought home strongly in the *1985 Reliability Review* by the North American Electric Reliability Council, in which the council said it "expects the reliability of electric supplies to decline over the next 10 years. . . . By the end of the decade, new capacity will be needed to provide a dependable supply of electricity for economic growth."

In former times such a forecast of need for new generating capacity would have been greeted as merely a statement of the obvious. For much of this century the demand for electric power grew predictably and exponentially, roughly doubling each decade. New generation facilities were planned accordingly, and reliability was taken into account by determining reserve margins on the basis of past experience.

Industry first developed the ability to do generation reliability calculations around the end of World War II. The methods developed at that time were not intended to assess the reliability of the transmission network (that is, they could not measure overall system ability to deliver power). From these early calculations evolved a familiar criterion: Generation reliability should be such that only once in 10 years would load not be met and that this level of reliability could be sustained by a generation reserve margin of approximately 20%.

Several factors have now greatly complicated the task of calculating acceptable reliability levels and have pushed the process of planning necessary reserve margins far beyond a simple criterion. Demand growth uncertainties, coupled with hard-to-estimate contributions of demand-side management and nonutility generation, confound forecasts of capacity requirements. According to EPRI's most recent *Electricity Outlook*, the amount of new generation that utilities will have to build by the year 2010 could vary from 250 GW to more than triple that figure, an enormous amount of uncertainty for an industry with a necessarily long planning horizon.

At the same time the rapid growth and increasing interconnections among utility systems led to recognition that transmission networks play a critical role in determining overall system reliability. Just having enough generation capacity to handle expected load cannot ensure reliable service if transmission is inadequate. Including transmission makes the task of calculating system reliability much more difficult than when only generation capacity is examined. In addition, planners attempting to improve system reliability must consider if it would be better to add a new generator to the grid of utility A or to build a new transmission line so that utility A can buy power from utility B, which has surplus capacity.

Further, the very concept of what is an acceptable level of reliability is changing. Recent studies have shown that sharp increases in the price of electricity have made many residential customers willing to accept lower reliability levels in exchange for lower rates. On the other hand, an increasing reliance on computers and automation has made many industrial and commercial customers willing to pay even higher rates for improved reliability. A previous article (*EPRI Journal*, March 1986) explored some of these changes in the value of reliability. This article will focus on new analytic tools that can help utilities cope with the increasingly complex problem of assessing reliability and planning system changes accordingly.

Questions of reliability have gained particular interest now that the costs of providing power have risen so sharply. "Reliability is the last major bastion of potential savings for utilities," comments Robert Iveson, the program manager of Power System Planning and Operations. "A new unit of baseload capacity costs as much as $4000 per kilowatt, and a new 500-kV transmission line may cost up to half a million dollars a mile. With such high costs, the ability of utilities to calculate system reliability more precisely for various reserve margins and transmission configurations could significantly minimize capital expenditures while optimizing customer satisfaction."

Measuring reliability

The ultimate cost of overall system reliability can be pictured as a U-shaped graph that planners sometimes call the bathtub curve. The left edge of the curve corresponds to the rise in costs resulting when reliability is so low that customers suffer expensive outages. The right edge results from the sharply increasing costs a utility would pay in order to increase system reliability beyond the point of diminishing return. The trick is to find the reliability level that corresponds to lowest overall costs.

When looking at generation reserve margins, reliability has historically been expressed in terms of annual loss of load probability (LOLP)—the number of days on which the peak load is not met because of too little generating capacity. Empirically, engineers found that this traditionally acceptable level of reliability lies near the minimum point of the cost curve.

As the complexity of utility systems increased, new indexes of reliability were needed in addition to LOLP, which could provide more detailed information. Such indexes were particularly important to utilities trying to develop data bases for the new generation of analytic tools that would be used to predict changes in reliability under various circumstances. The variation of cost with reliability may also differ substantially, depending on which index is used, so utilities will eventually be able to choose which set of cost curves best suits their particular needs.

An EPRI project completed in 1981 highlighted four alternative reliability indexes—expected hourly loss of load, expected energy not supplied, frequency of loss of load, and expected number of customers cut off. Another project completed in the same year developed procedures and formats for constructing a well-ordered outage data base from such typical sources of information as a system dispatcher's log. Several utilities and reliability councils are using these new definitions and data-gathering procedures to assemble input data for improved reliability evaluation codes.

Data related to the reliability of a utility's transmission system are frequently more difficult to assess than those related to the generation system. The fundamental reason is that power can flow along many parallel paths through a transmission network. Predicting failure of a component in the network can thus be quite complicated. An EPRI project completed in 1984 addressed this problem by developing statistical methods for analyzing the behavior of individual transmission system components, such as lines or transformers.

Researchers in this project were able to draw on 17 years of data on forced outages from Commonwealth Edison Co. By analyzing these data, the researchers first identified the principal factors that contributed to outages, such as substation arrangement, transmission line layout, transmission tower design, storms, and loss of major pieces of equipment (e.g., a circuit breaker). A computer code, TOPP, was also developed to predict transmission system performance on the basis of component outage data. This code was recently released for general utility distribution. Output from TOPP is provided in a convenient form for use in transmission reliability assessment codes.

Reliability modeling techniques

Once adequate data have been gathered and analyzed, the reliability of generation and transmission systems can be modeled. Usually each of the two systems is handled separately by making certain simplifying assumptions about the other. Recent EPRI work focused on improving the mathematical methods used in these models.

Previously, reliability models relied on a technique called state enumeration, which is the fastest way to analyze system behavior for specific contingencies. Using this method a planner asks, for example, what happens to a system when generator X or transmission line Y is forced out of service. For this technique to succeed, intelligent estimates have to be made about which system configuration is most likely to have problems.

The alternative procedure is to randomly consider the numerous operating states of a system and determine which will lead to outages. This Monte Carlo method is more time-consuming and costly but ultimately provides a more complete and accurate picture of system function than state enumeration. As its name implies, the Monte Carlo technique is a game of chance, which simulates a composite picture of system reliability through random sampling.

A third technique applies only to transmission reliability analysis. Called contingency enumeration, this method involves examining a prescribed set of contingencies and their effects on the transmission system.

Generation reliability

The Monte Carlo method was used to improve reliability modeling for generation systems in EPRI's GENREL computer code. In addition, GENREL is able to consider intermediate levels of generator operation rather than just assume each generator was off or on, a common practice in earlier codes. With these improvements, the model produces reliability indexes that more closely match field experience than did those produced by previous techniques. In an important early application of the code, Pacific Gas and Electric Co. used GENREL to obtain a more accurate assessment of reliability on its generation system.

Recently, GENREL was upgraded by extending its modeling capability to multiple service areas. In the new version, state enumeration methods can be used to analyze reliability in up to 10 interconnected service areas, and Monte Carlo simulation can be used in up to 3 service areas. Specifically, the new version of GENREL can be used to consider such questions as interarea transfer capability limits, multiarea generation scheduling, reserve requirements, and emergency action plans.

"This capability adds a new dimension to generation reliability calculations," explains Neal Balu, project manager. "Accurate modeling of these factors will help utilities evaluate alternative operating policies and better coordinate power transfers with neighboring utilities."

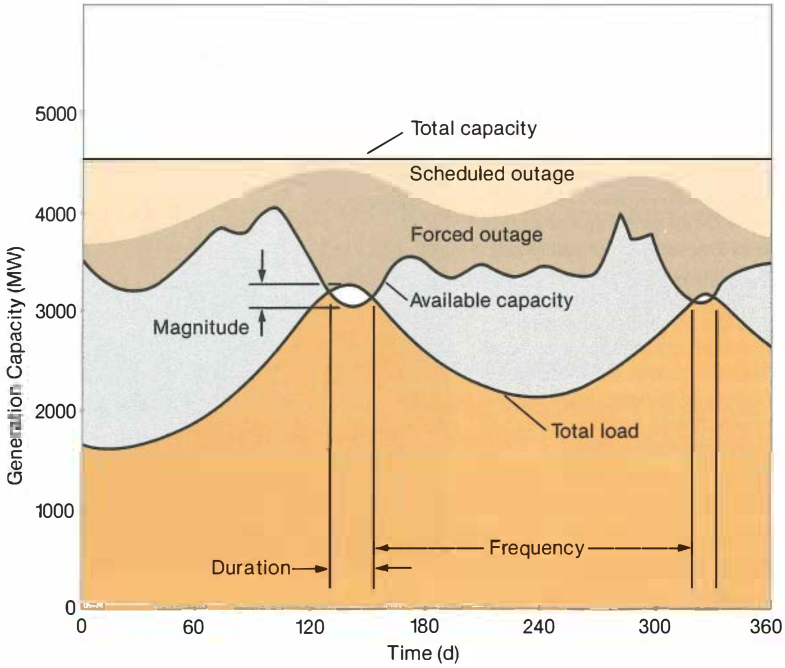
Transmission reliability

Because of the greater complexity of the transmission system, modeling of transmission reliability is one of the most sophisticated analytic problems faced by the utility industry, and related computer program development has thus lagged somewhat behind that of generation reliability. Recent EPRI work has thus concentrated on incorporating some probabilistic techniques into the analysis of transmission reliability problems, while stopping short of incurring the expense of full Monte Carlo simulation. In addition, the capability of considering independent outages of one or more generators was included in the models.

The result of this research was a computer program, SYREL, that can compute

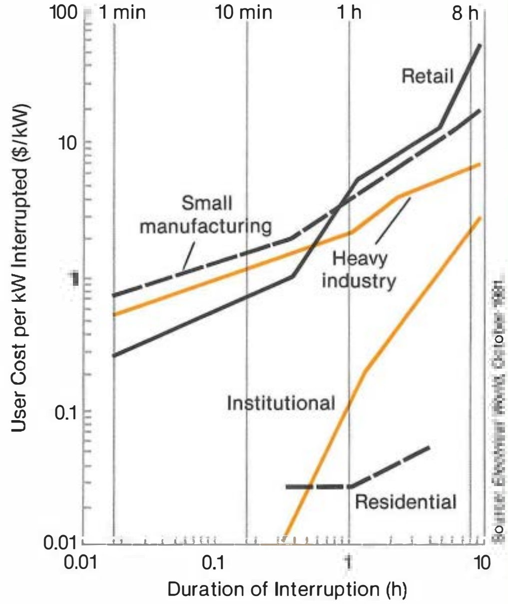
What Is Reliability?

Although maintenance outages are scheduled to leave the utility a good deal of reserve margin, forced outages can occasionally cause available capacity to dip below demand, especially during summer and winter peak periods. When this happens, the system's reliability is defined as a function of three basic factors: frequency (how often), duration (how long), and magnitude (how much load is not served). Reliability problems seldom mean outages for customers, as power is normally purchased from another utility to serve load, sometimes (as shown here) for as long as several weeks.



What Is Reliability Worth?

When a reliability problem does result in a power interruption, the cost to customers varies with customer type and the duration of the outage. Outages as long as several hours generally do not have a significant monetary effect on residential customers, whereas even a minute of interruption will reduce sales for retailers and bring production to a halt for manufacturers. Costs rise sharply for institutional customers after about 20 minutes, as offices decide to close down for the day rather than wait out the interruption.



multiple reliability indexes for transmission systems with up to 150 buses. To improve on the basic state enumeration method used in SYREL, a variety of advanced mathematical techniques were incorporated, which are based on the probability of various events occurring. These techniques included automatic ranking of contingencies for low-voltage problems, a more efficient enumeration scheme for multilevel outages, and procedures for computing reliability indexes over periods ranging from a week to a year.

Of particular interest is SYREL's ability to determine whether it is possible to eliminate a system problem through various remedial actions. Only when such remedial actions fail is a system failure counted. The severity of a failure can then be assessed by computing the amount and location of load curtailment.

Recently, Iowa-Illinois Gas and Electric Co. used SYREL to assess the financial risks and benefits of delaying construction of new facilities. The code provided analysis of reliability for different system configurations, based on single and multiple outages. "I expect to see more utilities use SYREL to work on this kind of decision-making problem," says Balu, "particularly in its expanded form."

Work is expected to begin later this year on extending the ability of SYREL to handle larger transmission systems, with up to 2500 buses. The first concern of researchers will be to determine which of the advanced techniques used in SYREL can be applied appropriately to a larger model. (A 150-bus model could be used to calculate reliability indexes for a major metropolitan area; a 2500-bus model could be applied to the transmission systems of most large utilities.) Consideration will also be given to incorporating a Monte Carlo capability into SYREL.

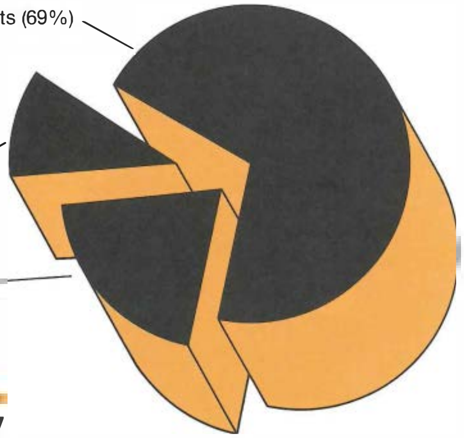
Composite reliability

An important limitation on reliability calculation methods used to date is their inability to model interactions between generation and transmission systems. GENREL, for example, can take into account specific transmission failures, and SYREL can handle certain generator outages, but these contingencies are treated as initial assumptions. No programs in general use have yet been able to model the combined generation and transmission systems simultaneously in order to calculate composite reliability—a measure of outages resulting from a combination of the effects on both systems.

According to existing models, about 70% of the reliability problems on bulk power systems result from generator outages and 30% result from transmission outages. Concern has been raised, however, that such calculations may be missing a significant number of depen-

Reliability on the Line

A high-voltage tower brought down by a tornado or thunderstorm, while providing a dramatic image, is only one type of transmission reliability problem. Often an outage at a plant requires that power be supplied by other generators on the system and be delivered through an alternative route; if the transmission facilities on this route are incapable of carrying the extra power, the transmission line is considered to be unreliable even though the structures and equipment are intact.



Composite Reliability

Models being used to characterize bulk system reliability in this country generally attribute about 70% of reliability problems to generation outages and about 30% to transmission outages; however, it is suspected that composite reliability, which considers effects resulting from the interaction of generation and transmission problems, may play a large role in overall reliability. In the example represented below, CEPEL researchers using Monte Carlo simulations found that composite effects accounted for over two-thirds of the outages on a sample Brazilian system.

dent outages that result from a chain of events involving system interactions. Failure of one generator, for example, might lead to overloading of a transmission line that carries power to a city from other generators. Such overloading might mean that the full capacity of these other generators would not be available to the city customers, causing a reduction in reliability and possible outages that would not be predicted by current models.

One initial indication of just how important composite reliability may be comes from work sponsored by EPRI and conducted at Centro de Pesquisas de Energia Elétrica (CEPEL) in Brazil. Using Monte Carlo modeling of a 24-bus reliability test system, researchers found that composite factors accounted for 69% of the outages, compared with 21% for generation and 10% for transmission. In other words, more than two-thirds of the reliability problems calculated for the system resulted from interaction effects.

Calculations were also conducted on another test system in which the total load level was eventually pushed to its limits. In these calculations, the contribution of composite reliability varied from 22% down to a negligible level as load grew. The reason, researchers found, was that generation problems tend to dominate reliability as load reaches its peak.

"Our work shows that the contribution from composite outages may be substantial," comments Mario Pereira, senior researcher at CEPEL. "The level of contribution, however, depends strongly on system configuration. We cannot yet draw general conclusions from work on these simple test systems."

The CEPEL results underscore conclusions soon to be published in another EPRI project, which was designed to evaluate research needs in the area of composite system reliability. The evaluation was conducted by Public Service Electric and Gas Co. (PSE&G) and concluded that future model development should include more provisions for system interactions. Both state enumeration techniques and Monte Carlo simulation were proposed to calculate these interactions. The recommendations also included a suggestion that EPRI invite more case studies from utilities, which could help provide a more accurate picture of composite reliability problems. Work on a new code to calculate composite reliability is expected to begin shortly.

"We identified a clear need to make sure reliability indexes are more realistic," reports Murty Bhavaraju, manager of reliability and advanced technology in the System Planning Department at PSE&G. "New models have to be able to account for transmission and generation outages together. Also, utilities want to see a sequence of events, not just a finite number of lines or generators that go out."

Future directions

So far, code development work has concentrated on the bulk power system—generation and transmission—leaving distribution systems to be considered separately. Although only about 10% of customer interruptions result from reliability problems on the bulk power system, these failures tend to be more dramatic, more widespread, and more significant in their effect on public opinion. The remaining 90% of customer outages result from problems on the distribution system, which affect smaller numbers of people at a time and result in less public outcry. Outages on small lines leading from the bulk power system to individual consumer loads also tend to result from factors outside a utility's control, such as storms and accidents involving roadside poles. Improving distribution reliability thus mainly comes down to such things as providing faster response times for repair crews and maintaining better control over tree limbs that might endanger power lines.

On a more theoretical level, interactions between reliability problems on the distribution network and the bulk power system would not be expected to be large. Loss of a transmission line may cause problems throughout a system; loss of a distribution line usually affects only its local service area. "Nevertheless," says Robert Iveson, "we have to take an increasingly integrated view toward reliability, including the distribution system. In particular, we have to agree on indexes of reliability that can be applied to the bulk power system and to local distribution networks, and then we have to use these indexes to improve data gathering. Eventually, it may be possible to develop analytic models that cover an entire utility grid and provide quantitative predictions of reliability as it affects customers directly."

Another type of analysis that is likely to receive increased consideration in the future is cost-benefit assessment of the steps necessary to improve reliability. On the bulk power system, for example, a utility might reduce the chance of outages by either building a new generator or adding a new transmission line. The decisions involving such alternatives can be quite complicated and are not adequately addressed by current models.

"Our ultimate goal is to provide utilities with powerful new planning tools that can take into account a variety of factors, including reliability," concludes Neal Balu. "The need for such improved analytic methods is rapidly becoming apparent. Transmission and generation systems are being stretched to their limits. The problem with today's models is that we can't really tell just how close we are to the edge." ■

This article was written by John Douglas, science writer. Background information was provided by Neal Balu and Robert Iveson, Electrical Systems Division.

TECH TRANSFER NEWS

Kentucky Utilities: A Benefits Profile

Both EPRI and a group of 24 member utilities learned a great deal from the Institute's 1985–1986 benefits assessment program. As reported in the September *EPRI Journal*, the program proved to be far more than a confirmation of the positive return that each utility received in exchange for membership. The two dozen utility participants—varying in size, fuel mix, type of ownership, and geographic location—also used the program to both review and improve their relationships with EPRI.

Kentucky Utilities Co. (KU) made the most of the recent program. Beginning with the benefits assessment, the utility has taken steps to enhance the body of information and the channels of communication it needs to achieve the greatest possible return for its investment in EPRI.

KU's participation in benefits assessment activities began in the summer of 1985. At the request of the utility's president, Technical Information Coordinator Wayne Lucas brought together a core of KU directors of engineering units in transmission and distribution, generation, operations, and fuel and of field offices. As a prelude to more detailed interactions, this group met with EPRI personnel to discuss goals and procedures.

After establishing guidelines, the KU core group designated staff members from company departments to review a compilation of EPRI research products and to identify and document the actual or potential benefits of these products. Seventy-five staff members from various levels within the organization—representing an impressive 60% of the technical staff—were selected. In December 1985 these individuals met in small workshops with EPRI personnel to share their findings and resolve some of the ambiguities attendant upon efforts to quantify benefits.

As reflected in its completed assessment, KU is benefiting from EPRI-sponsored R&D in a range of areas, including generation, transmission, load management, and response to environmental issues. Some of the products and studies proving especially beneficial to KU are methods for handling PCBs, system laboratory testing, boiler maintenance, evaluation of fuel inventory, studies and software for load forecasting and planning, and an array of electrical equipment, such as metal oxide lightning arresters and high-voltage circuit breakers.

KU's future options are based on its current 3100-MW generation capacity; 95% is coal-fired, and the remainder is fueled by gas, oil, or hydro resources. Planning for steady load growth of 2½% each year and for continued regulatory attention to acid rain and related emissions control issues, the utility is closely monitoring EPRI demonstrations and studies in coal gasification and fluidized-bed combustion technologies.

In assessing the current and potential benefits of these various products, the KU staff had the opportunity to learn more about EPRI, the range of its programs and products, and the technical help and information that the Institute makes available to its members. In some instances, the KU reviewers did not discover EPRI's involvement in some beneficial products until they had a chance to meet with EPRI personnel in the workshops. For example, the KU staff had been unaware of EPRI's role in the development of a fumigant treatment for wood poles that the utility has been using with excellent results (through a contractor) since 1981.

For some of the KU participants, the benefits assessment workshops sparked interest in new and expanded involvement in the transfer of EPRI-developed technology. As a direct result of the benefits assessment program, Ralph Altman and Bill McKinney of the EPRI Chattanooga office are currently working with the staff of KU's Brown plant to solve a precipitator problem—an issue that came to EPRI's attention during one of the workshop sessions. Wayne Lucas has taken more general steps to increase the distribution of EPRI report summaries at the utility and to use EPRI publications and videotapes to keep the staff informed of ongoing R&D.

In keeping with this goal of "spreading the word about EPRI" to all employees, Lucas installed the EPRI Publications Database (PUBS) on the utility's mainframe computer. Using the data base, the KU staff will be able to quickly refer to descriptive records of all EPRI technical reports, computer codes, the Results series of technology transfer documents, and other select publications. KU has produced a shortened users manual for PUBS and has worked to publicize EPRI in the utility's internal newspaper.

Another benefit of KU's participation in the benefits assessment program is the generally improved technical communications within the utility. At the workshops, personnel from the company's three largest power plants—Ghent, Brown, and Green River—had a unique opportunity to share their experiences and concerns. Since the workshops, the utility has solicited more information and assistance from EPRI, and Lucas reports more exchange of technical information at the utility, as well as more active involvement in technology transfer.

"In general, the benefits assessment improved awareness at our utility about how EPRI products will increase our choices in the years ahead and how EPRI has expanded the choices we're making right now," says Lucas. "Information and communication are the key elements in matching our problems to EPRI solutions." ■

Acidic Deposition Research Summarized

Acidic deposition has become a major air quality issue in both Europe and North America. Because fossil fuel power plants are significant sources of SO_2 and NO_x (two known precursors of acidic deposition), the electric utility industry has worked to better understand the relationships between emissions, acidic deposition, and environmental effects. In addition, the industry has sponsored extensive R&D on options for environmental management and emissions control.

For a concise, comprehensive summary of EPRI's research in these areas, decision makers in the utility industry, government, and public interest groups can turn to the *Acidic Deposition Catalog.* Designed as a convenient "point of entry" to more comprehensive information on EPRI's R&D, the catalog covers such research topics as pollutant emissions, atmospheric processes and deposition, ecological effects, economic assessments, emission control technologies, advanced clean coal generation technologies, and fuel planning. The project descriptions refer to relevant publications and computer software, hardware, and other equipment available under license. The technical project managers are listed as an additional resource. ■ *EPRI Contact: Steven Lindenberg (415) 855-2736*

Nuclear Research Documented

EPRI's Nuclear Power Division has developed a wide range of products that are either helping or expected to help electric utilities. More than 130 of these products are described in the *Nuclear Power Catalog*, available free to EPRI member utilities.

Each catalog description includes a product's benefits, utility application, availability, and associated publications. In addition, the catalog provides the names and telephone numbers of the EPRI technical project managers involved with each product. As pointed out in the catalog, many of these products—although developed for nuclear power applications—are suitable for nonnuclear (fossil fuel) applications and broad utility use. Overall, the catalog is designed to provide utility personnel with a reference for quickly locating EPRI projects in different areas of interest. For copies, call the EPRI Communications Straightline: (415) 934-4212. ■

Wind Power Instrumentation and Software Guide

A growing number of utilities are conducting wind resource studies and developing wind power stations. Preliminary studies require evaluation of potential sites, including measurements of wind speed, direction, shear, and turbulence. When a utility begins to build and operate wind turbines, it needs additional instrumentation and analysis tools to evaluate turbine performance.

A new publication, the *Wind Power Instrumentation Directory* (AP-4586), gives utilities quick reference to more than 50 specialized software and instrumentation products for evaluating wind resources and turbine performance at either prospective sites or pilot installations. The directory features one-page product descriptions arranged for ease of comparison in terms of data capacity, instrument accuracy, operating limits, and cost. In addition to this specific product information, guidelines are provided for technically sound evaluation of wind power resources and turbine performance. The directory also offers a glossary of commonly used terms in wind power technology. ■ *EPRI Contact: Frank Goodman (415) 855-2872*

Field Calibration for Coupling Capacitor Voltage Transformers

In 1980, Texas Utilities Electric Co. (TUEC) installed coupling capacitor voltage transformers (CCVTs) at a 345-kV switchyard. The lower cost and relatively high dielectric integrity of the CCVTs made them attractive alternatives for extra-high-voltage revenue metering. However, the utility became aware that CCVTs at other utilities were not performing as rated. Realizing that CCVT performance can degrade with time or be affected by stray capacitance and other conditions in the field, the utility looked for an on-site calibration method to verify that the installed equipment was metering accurately.

For a solution, TUEC turned to a prototype mobile field calibration system that had been developed by EPRI and the National Bureau of Standards under RP134. Field tests performed with the system in 1983 showed that the CCVTs were indeed performing as rated. Another test is planned during 1986 to verify continued accurate performance. Because the field-operable calibration system allows the continued use of the installed CCVTs, TUEC estimates a total savings of $87,000 between 1983 and 1992 due to the cost differential between CCVTs and conventional inductive voltage transformers. ■ *EPRI Contact: John Shimshock (412) 722-5781*

R&D Status Report
ADVANCED POWER SYSTEMS DIVISION

Dwain Spencer, Vice President

COOL WATER COAL GASIFICATION PROJECT—ALTERNATIVE COAL TEST

Cool Water is a nominal 100-MW (net) integrated coal gasification and combined-cycle (IGCC) power plant that uses the Texaco Coal Gasification Process. The plant has operated very successfully on its usual feedstock, a low-sulfur western coal. Two alternative coals—Illinois No. 6 (sponsored by EPRI) and Pittsburgh No. 8 (sponsored by Empire State Electric Energy Research Corp.)—were tested to evaluate the flexibility of the plant in handling a variety of feedstocks and its environmental superiority over conventional processes when running on high-sulfur coals. During the first quarter of this year, 32,600 t of the Illinois coal and 21,300 t of the Pittsburgh coal were gasified.

Recent tests of alternative coals at Cool Water have demonstrated that both Illinois No. 6 and Pittsburgh No. 8 coals are excellent feedstocks. The Illinois No. 6 test results are summarized in this article.

Overall plant efficiency based on the power produced and recovered sulfur heat content is the same at Cool Water whether the South Utah Fuel Co. (Sufco) coal (the design coal) or Illinois No. 6 coal is gasified. Typical performance parameters are shown in Table 1.

Plant heat rate is 200 Btu/kWh higher with the higher-sulfur Illinois No. 6 coal, but this does not impose an economic penalty for operation with Illinois No. 6 because revenues from sulfur sales compensate for most of this difference. This is a distinct advantage of IGCC plants over plants that use competing technologies, including direct coal combustion with stack gas desulfurization. Most of the competing technologies incur costs of several dollars per ton for disposal of the sludge formed from the sulfur they remove.

The best Illinois No. 6 heat rate, 11,770 Btu/kWh, was obtained without the benefit of the fuel gas saturator and also with poor performance by the heat recovery steam generator (HRSG). A heat rate of 11,200 Btu/kWh would be expected when running on Illinois No. 6 coal with the saturator in service and the HRSG performing as designed. The saturator was placed in service shortly after the end of the Illinois test. It replaced steam injection for NO_x control and has improved cycle efficiency. Engineering studies are under way to identify and correct the problem with the HRSG.

EPRI studies have shown that commercial IGCC plants could expect heat rates 2000 Btu/kWh lower than those at Cool Water by incorporating a combination of current and advanced technology into the plant design, primarily in the combined-cycle area (AP-3486). The greatest improvements would accrue from using a reheat steam cycle and an advanced gas turbine with a higher firing temperature. Figure 1 depicts the gasifier and syngas cooler.

Slurry preparation, gasification, sulfur removal, and recovery

The Texaco gasifier is fed with a coal-water slurry for safe, controllable operation. Preparation of the slurry is the first significant processing step.

At the start of the test, difficulties were encountered in transferring Illinois No. 6 slurry from the slurry preparation area to the run tanks in the gasification area. This had not been a problem with Sufco coal, which has a different rheology from that of Illinois No. 6. Many coal-water slurries are non-Newtonian Bingham plastic fluids, which must be subjected to a shear stress before they will flow. The Illinois slurry resisted flow in the low-shear environment of the sump tank and the transfer pump suction piping in the slurry preparation section of the plant.

Slurry transfer problems can be eliminated, however, by providing sufficient mixing in all slurry tanks and by ensuring an adequate net positive suction head for all transfer pumps, given the rheology of the slurry to be handled. Sufficient flexibility can be built in to accommodate a wide range of slurries.

Piping and equipment modifications were

Table 1
COOL WATER COAL GASIFICATION PLANT
(typical overall performance*)

	Sufco	Illinois No. 6
Raw coal HHV (MBtu/h)	1055	1080
Fuel to sulfur recovery (MBtu/h)	14	14
Power summary (MW)		
Gas turbine	70.4	73.7
Steam turbine	45.4	42.5
Auxiliary power consumed	6.9	6.9
Airco power (adj. for argon)	16.4	16.4
Net power	92.5	92.9
Sulfur to sales, HHV (MBtu/h)	1	9
Overall efficiency (%, inc. sulfur)	29.7	29.8
Heat rate (Btu/kWh)	11,550	11,770

*1000 t/d dry coal feed rate.

Figure 1 The structure containing the gasifier and the syngas cooler, with the slag conveyor and the slag storage hopper in the foreground.

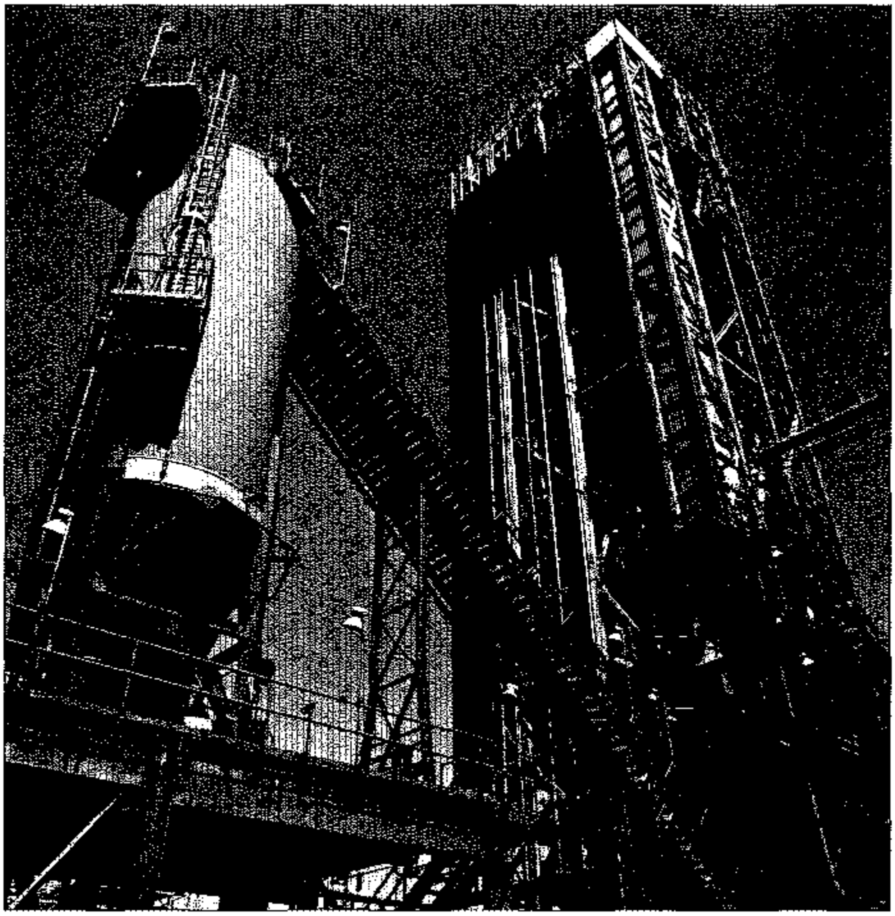


Table 2
GASIFICATION PROCESS PERFORMANCE
(Illinois No. 6 coal)

Dry coal	
Feed rate (t/d)	1000
Composition (wt%)	
Carbon	72.2
Hydrogen	4.9
Sulfur	3.1
Nitrogen	1.3
Ash	11.3
High heating value (Btu/lb)	12,970
Oxygen	
Flow rate (1000 ft^3/h)	910
Purity (%)	99.7
Clean dry syngas	
Flow rate (1000 ft^3/h)	2940
Composition (vol%)	
Carbon monoxide	44.8
Hydrogen (H_2)	38.4
Carbon dioxide	15.5
Methane	0.2
Nitrogen (N_2), argon	1.1
Hydrogen sulfide, carbonyl sulfide	0.0
Higher heating value (Btu/ft^3)	271
Syngas cooler steam production (1000 lb/h)	256
Overall carbon conversion (%)	97.2

made during the Pittsburgh No. 8 test to improve slurry handling. Time and material constraints precluded implementing these modifications during the Illinois No. 6 test, so an additive was used to alter the slurry rheology. Modest additive doses allowed slurries containing up to 65 wt% of solids to be produced and handled.

At commercial plants careful attention should be given to the mechanical aspects of slurry handling. There will always be some hardware limitations, however, and additives should be considered as a means of obtaining greater flexibility in handling a wider range of coals at higher slurry concentrations. EPRI studies have shown that the IGCC heat rate improves at higher slurry concentrations for Texaco-gasifier-based systems (AP-1429).

The two key parameters in evaluating gasifier performance are carbon conversion and gasifier refractory life. They are interrelated because carbon conversion increases at higher gasifier temperatures, but higher gasifier temperatures increase the refractory wear rate. Gasifier performance with Illinois No. 6 was excellent. At the selected optimal operating point, overall carbon conversion was 97–98%, and indicated refractory life was two years, assuming steady baseload operation. Table 2 summarizes the key performance parameters.

The lowest viable operating temperature of the Texaco system is just above the temperature at which the slag is too viscous to flow freely; the upper temperature is set by acceptable refractory life. A feasible operating range for Illinois No. 6 coal was determined during the Cool Water test. It was never difficult to achieve an indicated one-year refractory life with Illinois No. 6 coal, even at some of the relatively high temperatures tested. The ASTM slag fusion test (ASTM, D-271-48, 1948) provides guidance in determining the lowest temperature at which the slag will flow freely, but the slag viscosity–temperature curve is preferable for commercial operation. (The principles of the Texaco system and operating ranges are discussed in the *EPRI Journal*, May 1983, pp. 36–38.)

One additional mechanical constraint was observed at low gasifier temperatures during the test. At very low temperatures, where carbon conversion falls below about 95%, the Cool Water slag removal and process water systems became overloaded with unconverted carbon. Operation in this region must be avoided. A coal could be a problem in the Texaco process if the temperature necessary to obtain an acceptable hot face refractory life is lower than the temperature needed to obtain adequate conversion. We are optimistic that this will not be a constraint for most, if not all, coals in the Texaco process because the two alternative coals successfully tested at Cool Water are likely to be among the most difficult in this regard. Smaller-scale tests had indicated that high carbon conversion might be difficult to achieve with Illinois No. 6 coal in a commercial Texaco gasifier, and Pittsburgh No. 8 coal is a high-rank, low-reactivity coal that has posed conversion problems for some other gasification processes. Over 95% carbon conversion was easily achieved with both coals at Cool Water at temperatures corresponding to acceptable refractory life.

During the alternative coal tests, a great deal was learned about the relationship between laboratory, pilot plant, and commercial plant data on the Texaco Coal Gasification Process, particularly in the areas of carbon conversion and slurry preparation. More will be learned as data evaluation proceeds and when additional coals are compared at different scales. However, the coals tested to date—although very important resources—represent only a fraction of the combination of coal properties available. Therefore, it would still seem prudent to conduct a commercial-scale test to verify acceptable carbon conversion, refractory wear rate, and slurry characteristics before entering into a binding commercial contract for feedstock.

One of the major advantages of IGCC is the relative ease with which most of the sulfur in the feed coal can be removed and recovered for sale. The sulfur removal and recovery units (Selexol, Claus, and SCOT) performed very well during the high-sulfur coal tests.

The Selexol process removed sulfur compounds from the syngas before combustion in the gas turbine. Sulfur dioxide emissions from the gas turbine exhaust (i.e., from the HRSG stack) were easily kept below the permit limit of 175 lb/h (2.2 kg/s), which represents about 96% sulfur removal. More than 99% of the sulfur was removed during one test period. These high removal efficiencies are due in part to low carbonyl sulfide (COS) production in the gasifier. Hydrogen sulfide (H_2S) and COS are the two sulfur compounds produced in the Texaco Coal Gasification Process; COS is the more difficult to remove. As with Sufco coal, COS production with Illinois No. 6 and Pittsburgh No. 8 was less than one half the anticipated level.

The SCOT and Claus units consistently recovered over 99.5% of the sulfur for sale as elemental sulfur. Recoveries of over 99.9% were not uncommon. In general, the Selexol, Claus, and SCOT units all ran smoother and more efficiently with the higher sulfur coals.

Materials performance

The performance of system materials generally was very good. Corrosion probes indicated that the high-sulfur, high-chloride alternative coals did not accelerate corrosion or scaling of the process water systems. And no extraordinary steps were taken to control water system chemistry during the tests (e.g., increasing blowdown or adding corrosion inhibitors). Also, as previously noted, gasifier refractory wear rate was acceptable.

There was one definite materials problem: accelerated dew point corrosion was observed in the syngas cooler economizer. Apparently sulfur or chloride species in the raw syngas elevate the dew point above what would be expected from normal vapor pressure calculations. Fortunately, recent conceptual commercial plant designs do not include an economizer in the syngas cooler because all economizing can be accomplished more economically in the HRSG.

The only major disappointment in the alternative coal tests was that we were unable to determine with confidence the corrosion rate of the radiant and convective syngas cooler boiler tubes when operating with high-sulfur, high-chloride coals. The tubes are aluminized T-11 (1.25% Cr, 0.5% Mo) steel. Corrosion mechanisms are more complex and are different here than in other areas of the plant. Further, access was very limited. Consequently, exposure was simply not long enough to determine definitive corrosion rates of T-11 steel in the alternative coal environment. However, the limited examinations that were possible did seem to suggest higher corrosion rates with the high-sulfur, high-chloride coals than with the low-sulfur, low-chloride Sufco coal—an observation consistent with laboratory and syngas cooler pilot-plant experience with such coals.

Tube sections and corrosion coupons of some other promising materials were in very good condition, and further metallurgical examination will be performed. Of course, we will be able to determine the corrosion rate of T-11 steel with low-sulfur Sufco coal because it is Cool Water's regular feedstock. Longer operation with high-sulfur coals will be necessary, however, to determine the most cost-effective tube material for these coals.

Load-following and turndown

The results of load-following tests conducted when running Illinois No. 6 coal were very encouraging. During these tests, all controls were on automatic; no operator intervention was required, even at the oxygen plant. Stable rates of change of 4–5%/min were achieved over load changes of 20%. Indications are that the demonstrated rates of change will meet most utility load-following requirements. The maximum achievable rate of change at Cool Water is about 5%/min, a result of limits set by General Electric Co. because of the normal dispatch load rate limit of the gas turbine. However, for emergencies, such as a sudden frequency reduction, the gas turbine is able to pick up load instantaneously.

A dynamic model of the plant was developed by Philadelphia Electric Co. for EPRI (RP1133-1). When the actual plant configuration and controller settings were input to the model, it closely matched actual plant performance during the load-following tests. As a result of this impressive validation, it appears that engineers could adapt and use either this model or this modeling approach for other purposes (e.g., to evaluate more-complex commercial plant control configurations or to train operators). The model will be used at Cool Water whenever possible to evaluate proposed control modifications and to preview any future dynamic testing.

During the test of the Illinois No. 6 coal, performance data were gathered at 70% of design gasifier throughput. No gasifier performance deterioration could be identified at that level. However, combined-cycle performance does deteriorate at turndown, so the economics at Cool Water precluded formal testing at lower throughput.

Shortly after the conclusion of the alternative coal tests, a problem with the oxygen plant necessitated using the emergency backup oxygen supply system. To conserve the limited oxygen supply until repairs could be made, the gasifier was turned down to 40% of its design throughput. At that level the steam turbine had to be taken out of service because of inadequate steam superheat from the HRSG. The gas turbine then generated about enough electricity to meet plant auxiliary power requirements and to supply the air separation unit, had it been operating; that is, Cool Water's net power output was effectively 0 at 40% gasifier load. Of course, this is very specific to the Cool Water single-train configuration.

Heat rate deterioration at turndown is well known on single-train, combined-cycle plants. Multitrain commercial units would undoubtedly take individual gas or steam turbines off-line as load is being reduced, thereby achieving a reasonable heat rate across a wide gasifier load range. The performance of multitrain commercial plants at turndown would be expected to be significantly better than the performance at Cool Water.

Evaluation

In summary, the tests showed that Illinois No. 6 is an excellent feedstock for Texaco-gasification-based IGCC plants. Gasifier performance was very good, as evidenced by the high carbon conversion and low refractory wear rate. Sulfur removal and recovery of 96–99% was demonstrated, and all emissions (e.g., SO_2, NO_x) were easily kept below Cool Water's stringent limits. Significant insights were gained into coal-water slurry preparation and handling; operations in that section of the plant were very successful after some initial difficulties. Materials performance was generally good, but the tests with the high-sulfur coals were too short to permit selection of an optimal syngas cooler tube material for use with these coals. Further project background information, a process description, and design and actual performance data for Sufco coal are provided in AP-2487, -3232, -3876, and -4832. *Project Managers: John McDaniel and Edmund Clark*

EXPERT SYSTEM FOR GAS TURBINES

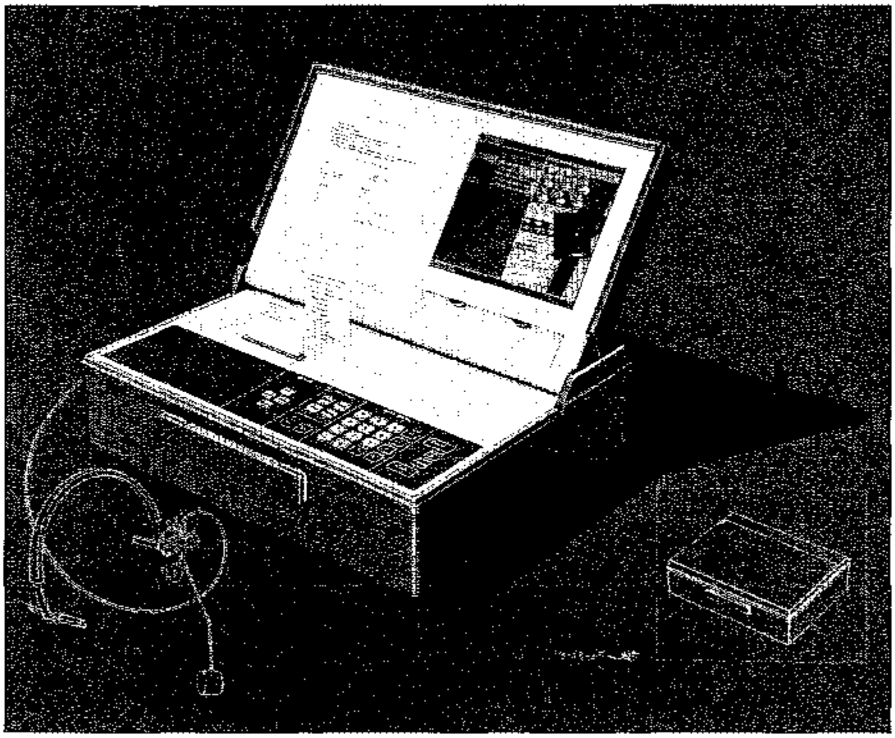
Expert systems, which are subsets of computer-based artificial intelligence systems, have been devised for uses as varying as medical diagnosis and geologic resource discovery. Now an expert system is being developed for troubleshooting gas turbines at electric power plants.

Late this year a field test of an expert system is scheduled to begin at Jersey Central Power & Light (JCP&L) Co.'s Gilbert Station in Milford, New Jersey. That test will be an important milestone in the use of expert systems in power plant applications. Designated EXACT (expert adviser for combustion turbines), this hardware and software system uses information provided by two experts to determine a sequence for diagnosing and remedying gas turbine problems. The JCP&L plant at which EXACT will be tested is a combined-cycle facility comprising four gas turbines, four heat recovery steam generators, and one steam turbine. Participants in the project include JCP&L (host utility); General Electric Co. (expert system); Honeywell, Inc. (user interface); and Arinc Research Corp. (measurements of effectiveness).

The General Electric team is responsible for developing the knowledge-based software that will reside in a PC and provide the necessary expertise for troubleshooting. Expert information, or rules, are placed into an empty shell expert system so that changes and additions can be made to the rule base without having to go back to fundamental programming. The empty shell expert system may be thought of as a higher-order language; it is to expert systems as Lotus 1-2-3 is to spreadsheets. This empty shell expert system is filled with rules developed by the two experts—one from General Electric's Gas Turbine Division and the other from JCP&L's Gilbert station.

Honeywell's contribution is a user interface unit, which consists of hardware and software that enable the user to query the expert system PC remotely from the gas turbine unit. Some state-of-the-art features being incorporated into this smart terminal include the LCD screens for text and video display, membrane keyboard, microprinter, voice interaction (recognition and synthesis), and power and communication connections (Figure 2).

Figure 2 Honeywell's design concept for EXACT's user interface. The interface permits the user to query the EXACT system remotely from the location of the gas turbine being checked. It combines a flat-panel video display, a keyboard, a printer, voice recognition and synthesis, and communications in a compact portable package.



Troubleshooting rules from the expert system are supported with video pictures from a video disk system that uses one-time recordable disks. Graphics overlays to the video pictures are also allowed, which enable dimensions and labels to be applied and easily revised. The video disk technology allows the display of individual video frames (e.g., schematics), as well as motion sequences.

Arinc Research will measure the performance of the expert system by comparing the effectiveness with which gas turbine troubleshooting can be accomplished with and without the EXACT system.

To provide a useful field test of EXACT, it was decided that the troubleshooting problems to be solved would have to be pertinent to the host utility, and the solutions would have to be in sufficient depth so as not to be superficial. These requirements, coupled with time and funding constraints, meant that the EXACT system to be field-tested would have to be rather narrow in domain but of a depth adequate to determine all probable causes of the particular conditions to be diagnosed, as well as a sequence of corrective actions.

The problems selected for EXACT's solution in this field test are control system electrical ground faults (including thermocouple grounds). These ground faults are one cause of gas turbine alarms and trips, and they occur often enough at JCP&L to provide a practical check of the EXACT system. Although this problem set is only one aspect of gas turbine troubleshooting, its complexity results in a rule-based logic system with a content equivalent to about 900 rules.

It is planned to run this field test for about a year while monitoring the results. Several other gas turbine problem areas have already been identified as possible candidates for future tests of expanded-domain EXACT systems. Selection of the subsequent applications will be made when warranted by sufficient progress in the development of the current system. *Project Manager: Clark Dohner*

R&D Status Report
COAL COMBUSTION SYSTEMS DIVISION

Kurt Yeager, Vice President

COLORADO–UTE AFBC DEMONSTRATION PROJECT

In southern Colorado on the western slope of the Rocky Mountains, Colorado-Ute Electric Association, Inc., is repowering its Nucla power plant with an atmospheric fluidized-bed combustion (AFBC) boiler. This unit will be the world's largest AFBC boiler using circulating-fluid-bed (CFB) technology. (CFB technology differs from bubbling-bed AFBC boilers in that virtually the entire bed of coal and sorbent circulates throughout the furnace; hot cyclone separators are incorporated into the CFB design to prevent gas with a high solids loading from entering the boiler's convection pass.) When completed, the Nucla CFB boiler will generate sufficient steam to produce 110 MW of electricity. EPRI is participating in the project and, on completion of construction, will sponsor a two-year test program to characterize and optimize the boiler's performance and to provide data necessary for scale-up to larger boilers. EPRI staff have assisted Colorado-Ute in making many of the key technical decisions associated with fluidized-bed technology.

Nucla is located 200 miles southwest of Denver. The original plant comprises three 12-MW units. In recent years these units became expensive to operate, and Colorado-Ute shut them down. Now, with a growing need for generation, these units will be repowered by the addition of a new 75-MW turbine generator and a new 925,000-lb/h (116.5-kg/s) CFB boiler supplied and installed by Pyropower Corp., a subsidiary of the Finnish conglomerate Ahlstrom. Steam at 1510 psig (10.4 MPa) and 1005°F (541°C) will be supplied to the new turbine. Autoextraction steam (369,000 lb/h; 46.5 kg/s) will be supplied to the three original turbines. Each of these will exhaust to its original condenser, and the condensate will be returned to a new, common deaerator (Figure 1).

Air, coal, and limestone reactions occur mainly in the combustor and hot cyclones of the CFB boiler. The combustor is divided into twin rectangular chambers. The walls are of membrane construction and are fully water-

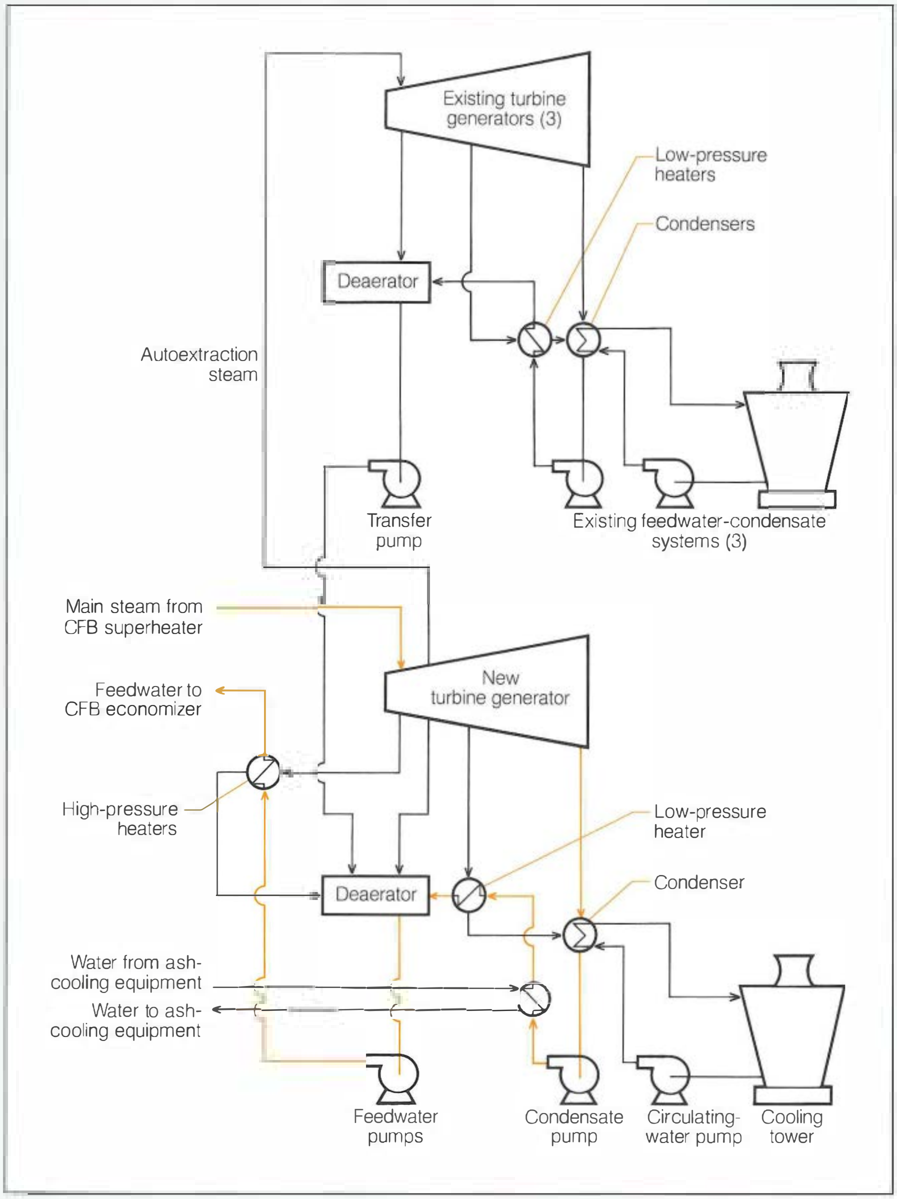


Figure 1 Flow diagram for the steam, condensate, and feedwater systems at Colorado-Ute's Nucla plant. The plant is being repowered with a 110-MW CFB boiler, which will supply steam to a new turbine generator; autoextraction steam will be supplied to the plant's three original turbine generators. (Color indicates main steam and feedwater flow.)

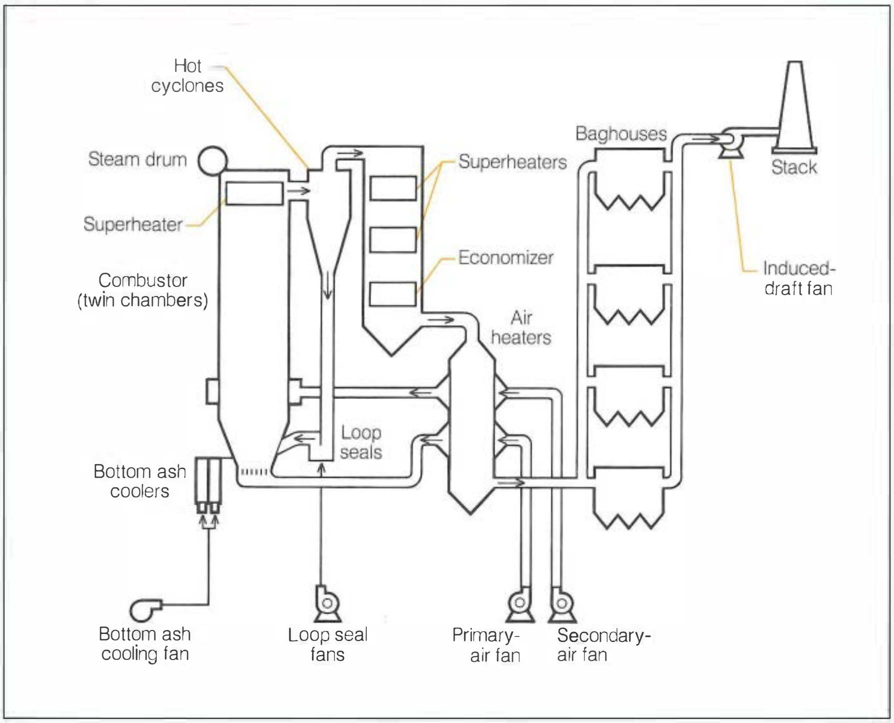
cooled; pressure is maintained at slightly above atmospheric. Flue gas exits the two chambers at the top and enters the hot cyclones, one attached to each combustor half (Figure 2). The hot cyclones and loop seals are made of carbon steel and lined on the inside with layers of refractory material. These refractory-lined components are being instrumented so that the effect of load following on the thermal gradients in these thick structures can be better understood.

The flue gas stream flows from the top of the cyclones into the convection zone of the boiler. In this area heat is transferred from the hot flue gas to steam in the superheaters and to water in the economizer.

Most solid particles entrained in the flue gas stream are separated and collected in the hot cyclones. These particles flow toward the bottom of the cyclones by gravity, are fluidized by high-pressure air in the loop seals, and are then transported back to the combustion chambers.

Among the key technical decisions with which EPRI assisted Colorado-Ute was the design of the combustor. There was considerable uncertainty about the scaling of this component. To reduce this uncertainty and to achieve a more conservative design, it was decided to use twin combustion chambers. Another key decision involved cooling of the air distributor; the water-cooled design selected has become a design standard.

Figure 2 Flow diagram for the air and flue gas systems at the Nucla plant. Because of uncertainty about scaling effects, the combustor of the new CFB boiler is divided into twin chambers; two hot cyclones will remove solid particles from the flue gas before it enters the boiler's convection pass.



Meeting industry needs

The EPRI-sponsored test program will be coordinated by a technical advisory group made up of representatives from several utilities and from EPRI and chaired by Colorado-Ute. The test plan is intended to address the needs of all the group's members. These include (1) optimizing the performance of the unit for economic dispatch on Colorado-Ute's system; (2) developing procedures and experience to facilitate efficient unit operation; (3) complying with environmental standards; (4) gaining experience on the use of alternative fuels in the unit; and (5) providing a basis for technical, economic, and risk assessment for future large-scale CFB applications.

On the basis of these needs, the following objectives have been developed for the test program.

- To confirm the feasibility of replacing existing stoker-fired coal boilers with an AFBC boiler that will increase both plant capacity and remaining life

- To optimize performance to yield the highest level of dispatch at the end of the test program—that is, to achieve the highest possible combustion efficiency at the lowest cost

- To support technology development by using the demonstration plant as an intermediate step between the test units and industrial CFBs that served as its design basis for future, larger units

- To demonstrate fuel flexibility on a commercial scale and to verify the operating parameters and design features that limit unit capacity for different fuels (as an integral part of the fuel flexibility work under RP1179)

- To perform integrated plant load-following, control, and duty analyses, to assess the applicability of the technology to various load-following and duty scenarios, and to identify rate-limiting design features

- To accumulate commercial design, cost, performance, and environmental control data for comparisons with existing and advanced power generation options

Test plan

To meet these objectives, the test plan addresses a number of technical issues. Through a series of parametric tests, the boiler's performance with the design coal will be characterized and optimized in order to enhance the potential for economic dispatch and expand the AFBC data base. These tests will explore performance as a function of several operating variables, including excess air, the ratio of calcium to sulfur, the ratio of primary to secondary air, and the fuel and limestone particle size distribution.

The test plan will also address the effects of scale on solids and gas mixing by varying several parameters that influence flow distribution. Because of uncertainties about scale effects, conservatism was built into the coal-feeding, limestone-feeding, and secondary-air systems. For example, the capacity of each of the four coal feed trains is 50% of full-load coal flow; hence the unit can be tested with only two trains. Other variables to be investigated are limestone feed distribution and secondary-air entrance velocity and location.

Another major effort will involve materials monitoring. The following will be evaluated: abrasion and corrosion of the distributor plate and nozzles; erosion/corrosion of feed ports, waterwalls, and refractory material in the lower portion of the furnace; erosion of waterwalls and superheater bundles in the upper portion of the furnace; corrosion of high-temperature alloys in superheaters and support structures; erosion of ducting, cyclones, and the convection pass; degradation of expansion and sliding joints by corrosion, abrasion, erosion, and wedging; and cracking or delamination of the layered refractory lining of the cyclones.

Fuel flexibility will be analyzed to demonstrate the capability of the unit to operate successfully on fuels other than the design coal. Other objectives are to correlate small-scale and large-scale test results and to validate the fuel characterization approach being developed in RP718 and RP1179.

Plant commercial performance statistics will be gathered to develop a data base for use in estimating the operating and maintenance costs of future units. Costs for main fuel and startup fuel consumption, sorbent consumption, operating and maintenance labor, maintenance materials and other consumables, and waste disposal will be considered, as well as by-product credits (when applicable).

The test plan also calls for monitoring startup and hot and cold restart characteristics and comparing them with vendors' predictions. Key questions to be answered involve the ability of the boiler to match steam turbine conditions, the amount of startup fuel (oil or gas) used, the startup rate, and the factors that limit startup.

Boiler turndown, load following, and rates of load change for critical operating parameters will be monitored in both the boiler and the balance-of-plant systems. The results will be compared with predicted values, and rate-limiting factors will be identified. An attempt will be made to improve load-following procedures.

Heat transfer will also be investigated, with efforts focusing on the main furnace. Heat transfer characteristics in the furnace of a CFB boiler are key to future scaling efforts. To keep the combustion environment over the full combustor height near the 1550°F (843°C) temperature needed for good sulfur capture, the heat release and heat absorption patterns must be in balance. With the type of CFB boiler at Nucla, this balance is attained by varying the ratio of primary to secondary air, which affects the heat release rate and pattern. In addition, the air ratio influences the solids density (voidage) profile up the height of the furnace, which in turn controls the rate of heat transfer. The solids density profile also varies with load.

Finally, the test plan calls for determining how AFBC particulates affect baghouse operability and performance. Compared with those from pulverized-coal units, AFBC particulates typically have smaller particle size, higher grain loading, and different physical and chemical properties.

Implementation

To implement the test plan, EPRI has developed a set of performance calculations for evaluating various plant operating conditions. These calculations perform energy and material balances around the boiler. The results will be used to monitor and optimize component and plant performance as well as to compare the performance of different plants.

Data required for the test plan and for the performance calculations will be logged, reduced, and stored on the EPRI mainframe computer at the plant. Signal outputs (representing data inputs) from plant process and control instruments and from additional test instruments specified by EPRI are provided via the data highway of the plant's distributed control system. Data from thermocouples, pressure gages, flow meters, and gas analyzers are averaged and stored. The complete data set for the performance calculation package will thus represent the average of data obtained over a test period.

The calculation package itself—consisting of FORTRAN 77 calculation subroutines, physical property subroutines, and a main driver program—has been tested on the EPRI mainframe computer by using design data sets. On-site implementation will follow in the next six to nine months, as the plant nears completion of construction and shakedown. The output on dependent performance variables from these calculations will be valuable in optimizing plant performance.

It is anticipated that the results from this test program—along with those from the AFBC demonstrations at Northern States Power Co. (RP2628) and the Tennessee Valley Authority (RP2543) and from other current AFBC programs—will enable utilities to confidently consider AFBC as a viable option for the early 1990s. *EPRI Project Manager: C. C. Lawrence III*

NO_x REMOVAL AS A BY-PRODUCT OF SO_2 CONTROL

Tests demonstrating effective sulfur dioxide (SO_2) removal by means of dry sodium sorbent injection upstream of a baghouse have frequently documented the simultaneous removal of nitrogen oxides (NO_x). Recently this phenomenon has come under increased study, as suggestions of a link between NO_x and such environmental problems as acid rain have focused attention on NO_x reduction strategies for utility power plants. Research is under way to understand, control, and optimize the NO_x removal associated with dry sorbent injection. If it is successful, utilities using dry sorbent injection for SO_2 control will be able to remove some NO_x at no added cost.

NO_x emissions from typical U.S. coal-fired plants are on the order of 900–1100 ppm for older units not regulated by the New Source Performance Standards and 200–400 ppm for new units using combustion modification techniques such as low-NO_x burners. These emissions are normally 95% nitric oxide (NO) and 5% nitrogen dioxide (NO_2). EPRI has sponsored several projects to evaluate methods of NO_x control, including pilot- and full-scale studies of low-NO_x burners and postcombustion processes (e.g., selective catalytic reduction). Most recently, it has sponsored laboratory and pilot testing on NO_x removal as a by-product of SO_2 control via dry sodium sorbent injection. It appears at present that this means of controlling NO_x works best in conjunction with a low-NO_x burner or some other in-furnace NO_x reduction technology; by inhibiting NO_x formation during combustion, such in-furnace technologies promote a high SO_2/NO ratio at the baghouse inlet, which enhances NO_x removal.

Early findings

The effect of sodium injection for SO_2 control on flue gas NO_x levels was first observed more than 10 years ago during nahcolite injection tests at the Mercer station of New Jersey's Public Service Electric & Gas Co. In those tests, NO_x (NO plus NO_2) removals of up to 40% were reported.

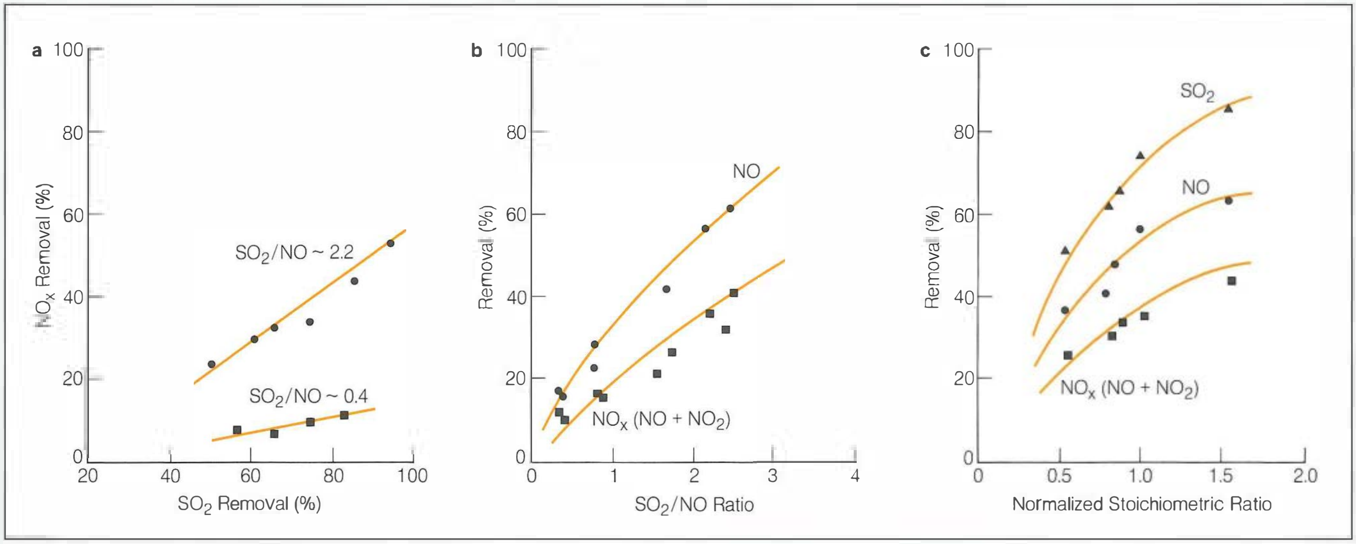
More-recent studies have confirmed these results. In bench-scale tests in 1980 using nahcolite for SO_2 control, KVB, Inc., found that 15% of the NO was removed when the normalized stoichiometric ratio (NSR) of sodium to SO_2 equaled 1. When the NSR was 1.7, NO removal rose to 25%. In full-scale nahcolite injection tests at Public Service Co. of Colorado's Cameo station in 1980–1983, 11% of the NO was removed along with 80% of the SO_2 at an NSR of 1. An NSR of 0.75 resulted in 8% NO removal and 70% SO_2 removal. The most recent full-scale demonstration of dry sodium injection was completed last May at the Ray D. Nixon station of the Colorado Springs Department of Utilities; there NO_x removal averaged 23% over a 30-day period during which SO_2 removal averaged 70%.

Because SO_2 removal was the primary focus of these studies, no effort was made to identify the mechanism for NO_x removal or to characterize factors influencing the amount of NO_x removed. To pursue these issues, in 1983 EPRI began funding project work at its Arapahoe Test Facility at Public Service of Colorado's Arapahoe station in Denver.

Current testing

Tests of dry sodium injection at Arapahoe have further confirmed the earlier reports that NO_x is removed along with SO_2. In these recent studies, NO_x removal reached 45% and SO_2 removal 85% at an NSR of 1.5. Data from the tests show that the higher the ratio of SO_2 to NO at the baghouse inlet, the more NO_x is removed. Also, higher NO_x and SO_2 removal lev-

Figure 3 Pilot-scale studies at the Arapahoe Test Facility investigated NO_x removal during dry sorbent injection for SO_2 control. The graphs show (**a**) NO_x and SO_2 removal for two ratios of SO_2/NO at the baghouse inlet; (**b**) NO and NO_x removal as a function of the inlet SO_2/NO ratio (normalized stoichiometric ratio of sodium to $SO_2 = 1$, SO_2 removal = 75%); and (**c**) SO_2, NO, and NO_x removal as a function of the normalized stoichiometric ratio (inlet SO_2/NO ratio = 2.2). In all cases flue gas temperature was about 300°F (149°C).



els are achieved as the NSR increases (as more sorbent is injected).

These results suggest that NO_x is collected in a two-step process in which sodium and SO_2 play a critical role. In the first step, it is believed, NO is oxidized to NO_2 via an as-yet-undefined intermediate reaction; this oxidation takes place as part of a larger reaction that produces sodium sulfate. In the second step, NO_2 (both the small amount produced in the boiler and the oxidized NO) combines with available sodium carbonate to form sodium nitrate, carbon dioxide, and some NO. These reactions are represented by the following equations.

$$Na_2CO_3 + SO_2 + NO + O_2 \dashrightarrow \text{intermediate reaction} \rightarrow Na_2SO_4 + NO_2 + CO_2$$

$$Na_2CO_3 + 3NO_2 \dashrightarrow 2NaNO_3 + NO + CO_2$$

Note that in the first reaction, each mole of NO yields one mole of NO_2. In the subsequent reaction, three moles of NO_2 yield a single mole of NO. It follows that the net achievable NO removal is about two-thirds, or 66%, and that under optimal conditions overall NO_x removal could also reach this level. Data from tests at Arapahoe appear to support this hypothesis, although the optimal NO_x removal of 66% has not yet been achieved.

As shown in Figure 3a, a higher ratio of inlet SO_2 to inlet NO is associated with higher levels of NO_x removal. The graph plots NO_x removal at Arapahoe against SO_2 removal for two inlet SO_2/NO ratios to demonstrate this effect. For example, when the ratio of SO_2 to NO equals 0.4 and enough sodium is injected to remove 60% of the SO_2, only about 8% of the NO_x is collected. When the SO_2/NO ratio equals 2.2, however, NO_x collection rises to about 30% when SO_2 removal is 60%.

Figure 3b illustrates the effect of the SO_2/NO ratio directly. Here NO removal and overall NO_x (NO plus NO_2) removal are plotted against the SO_2/NO ratio, with SO_2 removal held constant at 75%. As can be seen, NO removal increases as the SO_2/NO ratio increases. Note, however, that overall NO_x removal does not increase at the same rate as NO removal. This suggests that under the test conditions at Arapahoe, not all the NO_2 produced in combustion and by NO oxidation was able to react with the sodium sorbent. Preliminary data from Arapahoe and the R. D. Nixon full-scale studies indicate that a twofold increase in NO_2 emissions over inlet NO_2 levels can be expected under these conditions.

Figure 3c shows how the amount of sodium injected for SO_2 control affects NO_x removal. NO, NO_x, and SO_2 removal results are plotted against NSR at an SO_2/NO ratio of 2.2. As the NSR increases (as more sorbent is injected), the amounts of SO_2, NO, and NO_x removed also rise. Again, however, overall NO_x removal is not as great as NO removal alone, suggesting that not all the NO_2 produced reacted with the sodium (despite the increasing NSR).

Testing now in progress at Arapahoe is aimed at increasing overall NO_x removal from 45% to 60%; it will focus especially on NO_2 collection. The researchers will seek to identify the undefined intermediate reaction in the first equation above in order to enhance NO removal and will investigate the potential for increasing NO_2 collection by injecting additional reagents. *Project Manager: Richard Hooper*

R&D Status Report
ELECTRICAL SYSTEMS DIVISION

Narain G. Hingorani, Vice President

Candidate for Tech Brief

OVERHEAD TRANSMISSION

Transmission line structural development

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

A long-term payoff of this project will be the ability to simulate transmission structural system loads and response accurately without testing. Experience through testing is currently the only way to verify structural designs. Major structure innovations can take 10 years or longer to develop, using a proof test–only approach. In the short term, improved software that takes advantage of the increased horsepower of today's computer technology, coupled with the improved testing techniques available at the Transmission Line Mechanical Research Facility (TLMRF), can reduce development time and improve designs.

The role of RP2016 is to provide the structural software expertise to meet the research objectives of the TLMRF structural development project; the role of RP1717 is to provide the full-scale testing expertise to gather the basic data needed by the research project.

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

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

To date, the project has quantitatively defined how well existing analysis tools compute the response and failure mechanisms of transmission structures. Researchers have identified and developed some analysis techniques that improve the capability to stimulate the static behavior of transmission structures. Testing capability has been developed and hardware installed at TLMRF to perform and record dynamic tests on a section of actual transmission line. State-of-the-art finite element software has been developed and installed in the TLWorkstation system to allow future improvements to be plugged into the present software system.

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

Insulation design for HVDC transmission lines

EPRI research on insulation for HVDC transmission lines has two primary objectives: to develop design information and to develop improved dc insulators. This status report summarizes the results obtained to date and the projected course of future research efforts.

Insulation design on HVDC lines presents a substantially different problem than design for ac systems. The dc line charges particles in the air, which are deposited on the insulators and usually result in higher insulator contamination. When condensation, fog, or rain adds moisture, the absence of a voltage zero allows partial arcs to grow more readily into full flashovers. Utilities have reported more problems in contaminated areas for dc lines than for ac lines, and sometimes frequent washing is required.

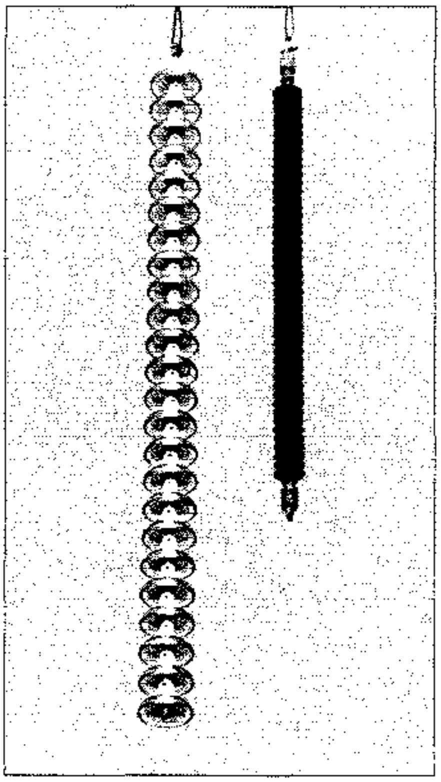
The recently published interim report EL-4618 presents the preliminary form of a reliability-based method for insulation design. The staff at EPRI's High-Voltage Transmission Research Facility (HVTRF) is continuing the development of this method, and the results will be presented in an HVDC transmission line reference book scheduled for publication in early 1988 (RP2472-3). In the meantime, designers of HVDC insulation systems should find the preliminary method useful.

Because the need for better-performing dc insulators is urgent, EPRI has sponsored several projects to achieve this goal. Researchers in one study, reported in EL-2151, optimized a composite (long-rod) polymer insulator (Figure 1). The flashover performance of contaminated insulators of this type is good and is generally higher than that for strings of ceramic suspension insulators of the same length. With the exception of the southernmost portion of the HVDC Pacific Intertie, designers have not used polymer long-rod insulators, citing lack of long-term mechanical strength data. Because of the generally improved contamination flashover performance of the polymer long-rod insulators, their light weight, and the polymer insulator's resistance to vandalism, additional data to better quantify their service life is an important need. Because long-rod porcelain insulators also generally have better flashover performance than do suspension strings of equal length, they may be an attractive option where vandalism is not anticipated.

Development of ceramic suspension insulators for dc systems has generally concentrated on design for resistance to corrosion and optimized shape to resist dc flashover. EPRI investigated the latter in a project by the University of Southern California. The objective was to develop an optimized shape based on theoretical aspects of data from laboratory tests on a variety of shapes cast from polymer concrete. Researchers also attempted to force

*TLWorkstation is an EPRI trademark.

Figure 1 Polymeric long-rod insulator (on the right) optimized for HVDC lines and developed in a cooperative research project by EPRI and Sediver, Inc. Both insulator strings have approximately the same contaminated flashover performance.



the deposit of contamination on the insulator's top surfaces by electrical field shaping. This concentration is desirable, because the top surface is cleaned by rain and wind, whereas the under surfaces are usually sheltered by deep skirts. The resulting insulator was referred to as an upside-down insulator, because the metal cap and pin were reversed in position to achieve the desired electric field shaping. Although the study achieved the contamination deposition objective, tests on prototype insulators showed that the overall flashover performance of the insulator was not any better than that of existing designs.

At HVTRF, investigators tested flashover performance of a wide variety of dc insulators with the objective of providing data for improved designs (Figure 2). Manufacturers and designers of dc insulators are urged to study the results of this parametric study (EL-4618).

In a project recently started (RP1903-2), Pacific Gas and Electric Co. and Bonneville Power Administration will each build dc insulator field test stations—PG&E on the coast at Moss Landing, California, and BPA, east of the Cascade Mountains at The Dalles, Oregon. A wide variety of dc insulators will be exposed to natural contamination under dc voltage stress and each insulator's performance observed. These data will be used to refine laboratory test methods to more closely duplicate natural contamination deposition and measure flashover voltage, and to develop better dc insulator designs.

EPRI work and published reports by others indicate the following findings.

- Insulator flashover is a more serious problem for dc than for ac, particularly in contaminated environments.
- Better-performing dc insulators are needed.
- Polymer and porcelain long-rod insulators show promise, and further research and testing is needed.
- Compared with ac, relatively little operating information on dc insulators is available, and data from the PG&E and BPA field test stations should be valuable.
- Considerable data on the flashover performance of contaminated dc insulators have been obtained at the HVTRF, and a major effort has been made to determine the in-service performance of full-scale strings of dc insulators in the HVTRF insulator test building.

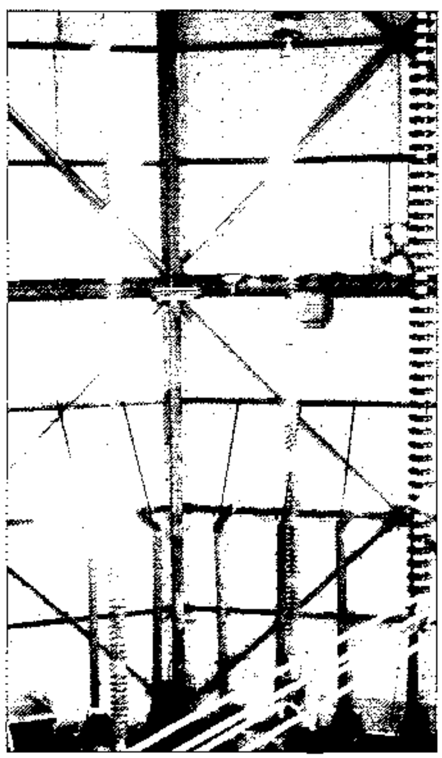


Figure 2 Electrical testing of HVDC insulators at EPRI's HVTRF fog chamber. EL-4618 provides information on how major dc insulator design parameters affect the electrical performance of contaminated insulators.

Additional research and development is needed if HVDC transmission is to reach its full potential. EPRI will continue its work in cooperation with member utilities and manufacturers to solve the existing problems. *Project Manager: John Dunlap*

TRANSMISSION SUBSTATIONS

GIS fault location system

Locating an internal fault in SF_6 gas-insulated substation (GIS) equipment is generally difficult, frustrating, and time-consuming. However, internal arcing in GIS enclosures creates heat that is detectable with infrared-sensitive equipment. Investigators in this project are developing two different, special-purpose infrared cameras (RP1360). Neither camera will require argon gas or liquid nitrogen for sensor cooling, which makes them suitable for long-term standby use. A principal criterion for the camera development is that the resulting products be low in cost. Because GIS equipment is stationary and thermal time constants are long, slow camera speeds are acceptable. Cameras producing an image in 15 to 30 s will cost less than the higher-speed thermal-sensing systems.

Each camera being developed will be coupled with a videotape recorder. A fault at a GIS facility would trigger a camera-recorder package to scan the substation equipment and make a complete thermal image on tape. Viewing the tape permits personnel to determine the fault location, as well as giving an insight into the extent of the damage quickly and accurately. Expedient fault location limits restoration delays, which shortens outage times and increases availability.

Xedar Corp. is developing a camera that uses a pyroelectric vidicon. The other camera, by ComPiX, uses a rugged, readily available lead-selenide, solid-state detector as the heart of its system. Both Xedar and ComPiX have assembled prototypes that are being tried in the field at a Louisiana Power & Light Co. substation. *Project Manager: Dennis Johnson*

HVDC converter transformer dielectrics

Transformers at HVDC converter stations have both ac and dc fields. The two types of fields behave differently in the solid and liquid insulations used in transformers. Ac electric fields in transformers distribute in inverse proportion to the dielectric constant of insulating materials. By contrast, dc fields distribute in direct proportion to volume resistivity (Ω-cm) of insulating material. The volume resistivity of conventional cellulose pressboard used in transformers is one to two orders of magnitude higher than the volume resistivity of insulating oil. Therefore, dc fields concentrate in the conventional pressboard, creating regions of high stress. It has been necessary to add material and space in transformers connected to HVDC converters to control dc stress concentrations.

Recent advances in dielectric technology have resulted in a low-resistivity pressboard. The application of this new WEPRI board (EHV Weidman Industries, Inc.–EPRI) in converter transformer high-stress regions could tailor the dc field distribution and reduce stress concentrations. Researchers are now developing a hybrid insulation system (RP1424-4).

General Electric Co. and Weidman are researching the resistivities, dielectric constants, and compatibilities of transformer oil, conventional T–IV cellulose pressboard, low-resistivity WEPRI board, and Nomex (duPont trademark), a higher-resistivity material made of aromatic polyamide fibers manufactured at Weidman.

Resistivity is a function of temperature, applied stress, and the time during which insulation is exposed to stress. In this project, researchers are testing materials at a variety of stress levels and temperatures to verify their characteristics under operating conditions. A major goal of this investigation is to measure changes in different combinations of materials and stresses that would redistribute stress concentrations. Tests are being made in a progression of small, large, and full-scale models. The work is entering the large-model phase at this writing.

With judicious use of WEPRI board, Nomex, conventional pressboard, and oil, engineering projections are that the main gap (the distance between the ac and the dc converter windings) can be reduced. A smaller main gap means a smaller core, lower core losses, and material and weight savings. The probability that a breakthrough will substantially reduce the size of converter transformer core/coil combinations is very high. *Project Manager: Dennis Johnson*

Pyrolysis and combustion of PCBs

The June 1986 *EPRI Journal* (p. 46) reported results of the pyrolysis and combustion of Aroclor 1254 at 100% concentration and as a 5000-, 500-, and 50-ppm contaminant in mineral oil, silicone, or tetrachloroethylene (RP2028-4). In all test fluids there were roughly linear conversion yields of PCBs to polychlorinated dibenzofurans (PCDFs) as the PCB concentration in the feed mixture decreased. Maximum yield occurred around 550°C in all cases.

In the past, tri- and tetrachlorobenzene (TCB) mixtures were frequently used to dilute higher-viscosity PCBs (Aroclor 1254 and Aroclor 1260). Because TCBs are known precursors for PCDFs and polychlorinated dibenzo-*p*-dioxins (PCDDs), the work at New York State Health Department included testing the TCBs under the same conditions as had been used previously for PCBs. Results differed sharply from the PCB tests. At all concentrations from 5000 ppm down, no detectable PCDF/PCDD formed. Detection limits in the TCB work were low enough that yields of PCDF and PCDD considerably lower than those anticipated for linear conversion would have been detected. Scanning mass spectrometer analyses of products from TCB pyrolysis in silicone show an addition of one or two methyl groups to the benzene ring to form chlorotoluenes and chloroxylenes. Temperatures of 750°C and higher decreased the formation of methylated compounds and almost completely destroyed the TCBs.

The in vitro bioassay to determine total PCDF-like physiological activity has made good progress. The technique termed flat-cell assay has been run successfully in silicone, RTEmp fluid (an RTE Corp. product), and mineral oil by using ultrasonics to homogenize the sample and the test medium, with the following results.

- About 3 ppm PCDF spiked into Aroclor 1242, 1254, or 1260 can be detected.
- Pyrolysis of Aroclor 1260 at 550°C for 15 min resulted in a 100-fold increase in flat-cell activity.
- A number of combustion samples in mineral oil were ranked for flat cell activity. Results were in line with those from gas chromatograph/mass spectrometer analyses.

Tetrachloroethylene tends to kill the cells that are the basis of the test, and solutions of PCB, PCDF, and PCDD in tetrachloroethylene have not been analyzed successfully.

Future plans include pyrolysis and combustion tests on pentachlorophenol, a compound used in large quantities for wood treatment. Additional work will be done to establish the useful limits of the flat-cell bioassay. *Project Manager: Gilbert Addis*

UNDERGROUND TRANSMISSION

Pipe-type cable joint restraints

Certain types of cables are manufactured in lengths of 2500–3500 ft (760–1070 m) for installation in steel pipes. These lengths of cable are spliced together in manholes, and the splices are enclosed in large steel joint casings. The daily loading changes cause a continual lengthwise expansion and contraction of the cables. For the most part, the undulations in the cable and the bends in the pipe system accommodate the expansion. The expansion phenomenon exerts a force on the cable known as thermomechanical bending (TMB). Typically, a transmission cable will undergo one heat-up–cooldown period per day (i.e., a daily load cycle) and will therefore see one TMB episode a day. Required reliability for transmission circuits dictates that cables accommodate TMB without damage during their expected lifetimes. One project addresses the reliability of cable subject to TMB in the pipe (RP7873).

However, potential problems may arise if TMB occurs at the splice within the joint casing, where the casing diameter is larger than the adjacent pipe. The result could be overbending, which causes the insulating tape on the splice to separate and severely damages the cable. To assess this situation, EPRI and Pirelli Cable Corp. have funded research on pipe-type cable joint restraint systems (RP7894). Public Service Electric and Gas Co. (PSE&G), whose engineers developed a splice restraint device, was a subcontractor on this project.

Users have always restrained joints—that is, have made a splice somewhat rigid within its joint casing. However, certain splice casing designs and rigidizing schemes in use have been found to be inadequate. The solution, therefore, has been to design and test joint restraint concepts that could ideally be retrofit to existing pipe-type cable joints. Two general approaches have evolved, each with numerous variations.

- Rigidize or restrain the splice assembly to prevent all radial motion but allow some longitudinal motion within the joint casing
- Rigidize or restrain the splice assembly and fix it within its joint casing, allowing no radial or longitudinal motion

The first approach impresses only modest mechanical forces on the splice assembly because the longitudinal motion of the cable itself accommodates most of the cable expansion. The risk in a real field situation is that the longitudinal motion may be greater than the design value and cause severe bending. The second approach eliminates splice movement entirely but impresses high mechanical forces on the joint restraint assembly. The risk in this method is that even small amounts of slippage or motion may result in tape separation and electrical distress.

Project results to date have been encouraging but mixed. The PSE&G–designed restraint device (*EPRI Journal*, October 1983, p. 46) was tested on both crepe paper– and hard-paper–insulated 345-kV joints and performed extremely well. The design fits into the second approach mentioned above, and it has been installed commercially. Another joint restraint design fitting the first approach and in commercial service for many years was tested and also performed well. Consolidated Edison Co. of New York, Inc., funded the design work and testing. A third design, fitting the second approach, uses lengthwise rigid rods. The splices were not adequately tied to the rods with nylon tape, and the splice slipped and failed. A design modification is being considered to rectify the weakness. *Project Manager: John F. Shimshock*

PLANT ELECTRICAL SYSTEMS AND EQUIPMENT

Generator unbalanced load capability

As generator ratings have increased and as electrical load characteristics on utility transmission systems have changed, the capability of generators to operate with unbalanced electrical loads has decreased. Such loads produce asynchronous magnetic fields in the generator that cause inductive heating on the rotor. The most severe outcome of this kind of thermal distress may catastrophically damage the rotor forging and the slot wedges, which constrain the field winding against centrifugal force effects. Unbalanced loads are created when the currents in the three phases are not of equal magnitude or the angles between the three phases are not equally displaced.

Another heat-inducing phenomenon that is becoming increasingly important stems from the operation of solid-state power electronics. The high-speed switching characteristics associated with such devices as thyristors, silicon controlled rectifiers, and diodes produce harmonics on the transmission system that ultimately result in magnetic fields in the generator air gap that do not rotate in synchronism with the rotor. This form of inductive rotor heating is continuous, and it reduces the transient thermal capability of the rotor forging.

A more severe form of transient rotor overheating occurs when a generator is started as an induction motor. If a generating unit has been shut down but the generator is accidentally connected to the electrical system, the generator rotor behaves like the rotor in an induction motor, and the turbine generator shaft begins to accelerate. This asynchronous operation causes severe generator rotor overheating.

A project to study this problem has concluded that the greatest causes of generator rotor transient thermal overheating were asynchronous operation, out-of-phase synchronizing, and transmission system faults that result in unusually high unbalanced currents (RP2554). The final report published as part of the study describes several proposals for changing generator rotor design, as well as steps that could reduce some forms of unbalance on the electrical system. The report also examines various alternatives for balancing technical and economic considerations. *Project Manager: James S. Edmonds*

Standstill frequency response

Several test methods have been identified for developing transient parameters for large turbine generators. These tests have been completed in this project (RP2328), the data have been collected, and researchers are analyzing the results to determine the quality of each of the three methods.

Personnel conduct a standstill frequency response test on a generator while the machine is shut down and the turbine generator shaft is at a standstill. This test is attractive from an operations point of view because it can be performed during a unit outage. A full frequency spectrum of current is first applied to the rotor winding with the rotor in the direct axis position; then a second set of data is taken with the rotor aligned with the quadrature axis. Because the lower frequencies take much longer to complete, the entire test procedure is time-consuming.

Analysts test stator decrement on the generator at very low electrical load levels; these tests yield data for developing transient parameters for generator models. Data are collected when the unit is tripped and for a short period after, while the field winding is still energized. The data approximate the generator behavior under operating conditions but at practically no load.

On-line switching tests yield transient data under the loading conditions most likely to be encountered at the time of an actual system disturbance; line switching tests are conducted when the generator is at its electrical operating load level. Researchers initiate a disturbance manually by opening and closing a designated circuit breaker on the transmission system. This electrical disturbance causes the generator to respond according to its unique transient characteristics. By measuring key electrical data, personnel can develop a model for use in electrical system transient stability programs.

This last test is the most accurate method for determining the generator transient data. However, it is difficult to perform because it requires system and manpower coordination. Researchers in another project developed a procedure in which a monitor can be installed on a generator to collect electrical and mechanical generator data continuously (RP2328-3). Any time a system disturbance of predetermined magnitude occurs, the monitor will capture these data and store them for analysis. This information can yield the most accurate generator transient parameters, which researchers can use to corroborate off-line generator tests. *Project Manager: James S. Edmonds*

R&D Status Report
ENVIRONMENT DIVISION

Stephen C. Peck, Acting Director

FOREST DECLINE: A REVIEW OF THE SCIENTIFIC LITERATURE

There have been recent reports of an unprecedented dieback and decline of forests in Europe and North America. During the past two years, EPRI's Environmental Data Analysis (EDA) Program staff and consultants have been analyzing the relevant published scientific literature (RP5002). The results of their analyses are described in a new EPRI publication, Forest Health and Acidic Deposition: A Synthesis Report *(EA-4813-SR). The report describes the current state of knowledge about forest decline in North America and catalogues the possible causes for the decline observed in some tree species in certain geographic areas.*

The EDA report considers 14 major field studies that examined forest decline where acidic deposition might be a contributing factor. These studies were conducted at 17 forested sites in the eastern United States (Figure 1). In addition to a critical evaluation of the published scientific literature on forest decline in North America, the report includes detailed discussions of forest ecology, hypotheses about forest decline, and research by EPRI, the federal government, and others.

For quick reference, much information from the EDA review is outlined in tables in the report's executive summary. These tables cover the following.

- What we know and do not know about forest dieback and decline
- The major hypotheses being considered to explain observed forest symptoms
- Selected case studies of forest decline and the major components of those studies
- The funding levels of research investigating the major hypotheses about causes of forest decline

Table 1 here, which summarizes the current state of knowledge about forest decline, illustrates the usefulness of this format.

The EDA analysis found that the extent of forest decline in North America confirmed by scientific studies is far more limited than a casual reading of press reports might suggest. Most research considers a single species—red spruce. Many of the studies purporting to document forest decline failed to use the quantitative measures of tree population density and tree biomass that are necessary for evaluating a forest's overall health. For example, foresters know that as a forest matures, it tends to develop a greater proportion of older and larger trees. Competition for sunlight, water, and nutrients may tend to decrease the number of younger trees. Although the total number of trees declines as the forest ages, the total biomass of the forest may still be increasing or stable.

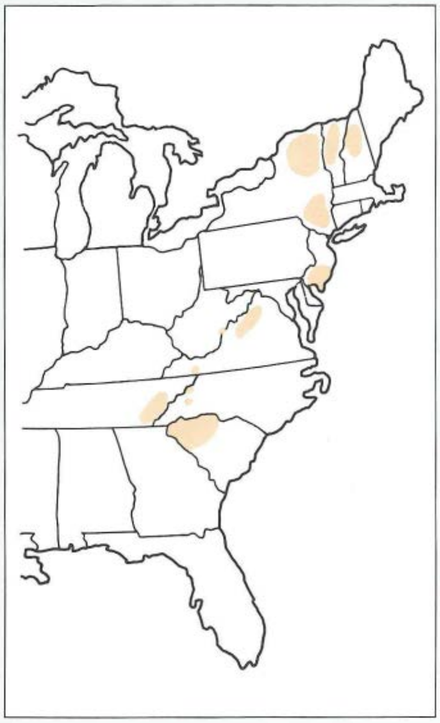


Figure 1 A recently published EPRI report on acidic deposition and forest health (EA-4813-SR) evaluates the conclusions of 14 case studies covering 17 sites in the areas shown here. Forest decline has been documented only for red spruce at high elevations.

The rate at which trees grow can fluctuate dramatically as a result of natural conditions. For example, red spruce trees often grow very slowly under a canopy of larger trees: a 2-m-high red spruce in a deeply shaded area may already be 40 years old. When the canopy opens up as the taller trees are harvested or fall naturally, the red spruce can experience a rapid growth spurt. Studying tree rings can provide evidence of the historical growth rates of trees. Interpreting the changes observed in annual growth increments requires substantially more information, however, not only on the climatic (and perhaps pollution) conditions that existed, but also on the relationship of the study individual to other individuals of the same and different tree species in the surrounding area during the growth period.

Other natural environmental conditions may induce decline and dieback in some forest species. In the northeastern United States, red spruce often grow at higher elevations in combination with balsam fir. The fir in one area all tend to be about the same age. Periodic dieback of the fir occurs. The falling trunks of the dead trees can damage neighboring healthy trees and leave neighbors open to more wind and frost damage. But the opening of the canopy also spurs the growth of new seedlings among the trunks of the dead trees, and they rapidly fill in the opened area. This "fir wave"—the progression of patches of dead trees through apparently healthy communities—is a well-recognized phenomenon of spruce-fir forests. Red spruce do not exhibit the same sort of wave cycle, or at least it has not been identified in this very long lived species (typical life is 300 years).

The EDA analysis of the scientific literature does confirm, however, that red spruce populations are experiencing a statistically significant decline in some high-elevation forests in the eastern United States. These are areas

Table 1
CURRENT STATE OF KNOWLEDGE ABOUT ACIDIC DEPOSITION AND FOREST DECLINE

What Is Known	What Is Not Known
□ Some tree species in North American forests are experiencing dieback, increased mortality, and apparent growth decline.	□ The primary cause(s) of forest decline; the geographic extent of damage; the percentage of the tree population affected
□ In Germany, Norway spruce and fir, as well as broad-leaved species, have experienced dieback and increased mortality more and more rapidly since 1982; symptoms affected an estimated 50% of forests as of 1984.	□ The cause(s) of forest decline and associated symptoms in Germany; the extent of damage to forests; why the addition of calcium and magnesium to the soil has initially alleviated some symptoms
□ Forests in which the decline has been studied have elevated airborne-pollutant concentrations and deposition rates.	□ Historical rates and trends of airborne-pollutant concentrations and deposition; if some areas with high pollutant loading have no tree damage or, conversely, some areas with low loading do have damage
□ Although sulfur and nitrogen are soil nutrients, excess concentrations of their oxidized states can leach other nutrients from the soil.	□ The extent to which historical and current rates of deposition of these materials have depleted or are depleting nutrients
□ Many tree species undergo periodic cycles of mortality.	□ The contribution of natural variables (e.g., climate, pathogens) and man-made variables (e.g., land use, forest management practices) to observed symptoms
□ The movement of nutrients, as well as other chemicals through the forest ecosystem, and the relationship of that movement to chemical input by precipitation, is highly complex and variable over time and among forest types.	□ The mechanisms within these complex systems (and hence how to ascribe symptoms to specific causes)
□ Trees react to water availability, but annual average precipitation (the only commonly available measure of moisture) is insufficient for evaluating how the seasonality and timing of soil moisture relate to tree growth and health.	□ Detailed historical rainfall patterns for most forest areas exhibiting dieback, decline, and increased mortality
□ Many soils in forest study areas are acidic and nutrient-poor for reasons unrelated to pollutants.	□ Whether pollutants are exacerbating poor soil conditions
□ Experiments using simulated acid rain have shown that rain more acidic than typical acid rain can have measurable effects on plant leaves, and that rain chemically similar to typical acid rain can leach nutrients from soils like those in areas of forest decline.	□ How to extrapolate the data collected in controlled experiments to different species under field conditions

where logging and other factors may have isolated colonies of red spruce into a genetically uniform population. These isolated stands may be less capable of withstanding any stress, natural or man-induced, in their now-marginal environment.

Acidic deposition is considered to be one possible contributing factor in the decline of red spruce. Several hypotheses related to acidic deposition are being actively investigated in both laboratory and field research. Among the hypotheses are the following.

□ Acidic deposition may leach nutrients from needles and soils and reduce tree photosynthesis.

□ Acidic deposition may mobilize metals in the soil and produce toxic effects in trees.

□ Nitrogen compounds in the air and in precipitation may be deposited on a tree in excessive quantities and produce a fertilizer effect. According to this theory, the nitrogen spurs tree growth for too long into the autumn, so that the tree does not properly "harden" for the winter. The tree could then suffer severe frost and/or desiccation damage to its younger needles in cold winters.

In addition to pollutants, there are numerous natural conditions that may contribute to, or be the sole cause of, forest decline—for example, drought, severe storms, pathogens, and insects. Even the natural succession of tree species may be involved. In fact, most scientists now agree that a combination of many factors is probably involved in each unexplained instance of forest decline, and that the specific combination differs from case to case.

Red spruce is the only tree species in North America for which there is clear evidence of decline. Scientific studies suggest that acidic deposition, along with other factors, is playing a role in this decline. Declines in other populations, including sugar maple in eastern Canada and New England and loblolly pine in the southeastern United States, are suspected but are not as yet rigorously documented; these two species are the subject of intense scientific investigation at this time.

Much of the research on causative factors is now moving away from an exclusive concern with acidic deposition toward a consideration of other atmospheric compounds as well as natural stresses. High levels of ozone, the chemical by-product of reactions between hydrocarbons and nitrogen oxides in sunlight, are known to be toxic to many agricultural crops. Southern California studies provide strong evidence for Ponderosa pine dieback in the San Bernardino mountains from chronic exposure to high concentrations of ozone-rich photochemical smog. Some findings in the southeastern United States and in Europe implicate ozone as a contributing factor. The EDA program is now conducting an analysis of the scientific literature on ozone and forest health. The findings will be described in another synthesis report, to be published in early 1987. *Technical Manager: Charles Hakkarinen*

MODELING FISH POPULATIONS

Environmental impacts on aquatic ecosystems are of increasing concern to industry, government, and the general public. The regulatory requirements that limit impacts on fish from thermal discharge, entrainment, chlorine, and metals also affect power plant operations and capital costs. Thus the utility industry must address both the ecological and economic effects of combustion processes and cleanup procedures that may result in the emission of toxic materials to natural waters. To help in this effort, EPRI's RP2553 has derived a microcomputer-based methodology for predicting fish population survival or demise under various natural and man-induced conditions.

Ecological damage can be defined at three levels: individual, population, and ecosystem. While the response of individual organisms to pollutants can be studied in a bioassay, predicting the effect of pollutants on populations is more difficult because of the possibility of equilibrating mechanisms. The most complex level is the ecosystem, which includes the interaction of all plant and animal species in a common environment. If even a single population is disturbed, the effects may be felt by some or all other species within a given ecosystem.

RP2553 has focused on population effects in aquatic environments. Specifically, it addressed fish biology, both because fish are of economic importance and because they are commonly considered indicators of the health of an aquatic ecosystem. In this project EPRI has produced a methodology and corresponding software, RAMAS (risk analysis and management alternatives system), for estimating potential anthropogenic impacts on fish populations.

The RAMAS approach

A model of fish population dynamics must recognize that changes in mortality stemming from the use of water in power generation tend to affect young fish most severely. Some anthropogenically induced fish death is associated with entrainment in water intake flows or with thermal or toxic pollution of the habitat. Because eggs and larvae cannot resist entrainment and are particularly sensitive to thermal and toxic effects, they commonly sustain most of the unnaturally induced mortality. (The survival of these early age classes of fish is also greatly affected by natural variables, such as food supplies, predation, and weather fluctuations.)

Classical fishery models generally are not sophisticated enough for impact assessment because they do not address uncertainty. The focus of an assessment should be to calculate the risk of approaching extinction that a population may face and the sensitivity of this risk to potential variations in impact.

The RAMAS model allows for differentiation by age class and density-dependence factors while addressing risk and uncertainty. Furthermore, it is based on readily available biological data. Using vital statistics for a population as input (i.e., data on various life history parameters), RAMAS predicts future population sizes, their expected variance, and the chance that the population will at some time fall below a prescribed level of abundance.

The RAMAS approach is based on demography, the branch of quantitative ecology focusing on the dynamics of age-structured populations of single species. Age structure usually implies a division of individuals into discrete age classes, or cohorts, which successively age at each time step. Probabilistic (Monte Carlo) techniques are incorporated in the RAMAS population dynamics model to represent the effects of random variation in survival rate and birth rate (fecundity) from each age class.

RAMAS provides insights on important issues in ecological risk assessment: how to estimate the risk of extinction or near-extinction, how to calculate the impact of man on mortality, and how to calculate the effect of decreased birth rate on a population. For a specified time period, the model generates a series of replicate trajectories (plots of abundance over time) on the basis of age-specific birth rates and survival rates in various cases involving natural or man-induced conditions. From the trajectories and a specified critical abundance level, probabilistic estimates can be made for the risk that a population will fall below a threshold level of abundance. This approach is simple and direct.

Using RAMAS

RAMAS is a user-friendly, menu-oriented program for the IBM PC family of microcomputers. Users can build their own population models by specifying age-structured information on survival and birth rates; density-dependence characteristics; and the degree of uncertainty associated with estimates of the parameters.

To specify the model fully, the user must enter certain information for each age class—maximum age, sex ratio, natural mortality rate, birth rate, and initial population size—along with the number of generations to run the model and the number of replications to be produced. Provisions are made for normal, lognormal, and arbitrary distributions of birth rates, first-year mortality rates, and older-than-first-year mortality rates, as well as for correlations among these quantities. It is also possible to specify (1) effects that are dependent on population density, and (2) man-induced mortality as a separate class of age-structured variable. Thus the user can estimate how deaths above the natural level affect population dynamics. The input can be defined interactively or through disk files.

To date, RAMAS has been used to characterize the population biology of seven important fish species: cod (*Gadus morhua*), Atlantic herring (*Clupea harengus*), yellowtail flounder (*Limanda ferruginea*), striped bass (*Morone saxatilis*), American shad (*Alosa sapidissima*), white perch (*Morone americana*), and haddock (*Melanogrammus aeglefinus*). These species were chosen because extensive data sets on their life histories are available. The procedures for estimating the parameters used in RAMAS for these seven species and the study results will be detailed in a forthcoming EPRI report.

The study, which used both published and unpublished data, attempted to establish normal levels of variability in certain life history parameters. The major characteristics considered were breeding biology, longevity, sex ratio, age- or size-specific birth rates, and age- or size-specific survival rates. Some related vital statistics, such as growth rates and length-weight relationships, were used to help estimate these parameters.

The RAMAS output from the case study suggests two interesting hypotheses. First, density dependence appears to be crucial in maintaining stable populations. In general, when density-dependence factors were omitted from the model, the populations went extinct or grew to unreasonably large sizes; when the factors were included, populations stabilized to apparent equilibrium or gently oscillating cycles. Second, given the background level of natural variability in mortality and birth rates, it appears that a moderate additional level of man-induced mortality may not have a discernible impact on the long-term behavior of a population.

The study shows that RAMAS can be used to test the effects of man-induced mortality in hypothetical situations and to perform sensitivity analyses. Once the user has accumulated information on the central tendencies and variabilities of life history parameters, specific predictions can be made about the expected trajectory of a population and the variance associated with it. These predictions can be translated into the common denominator for comparing economic and ecological consequences: risk.

The next step in this research is to develop models and methods for estimating impacts at the ecosystem level. This is the subject of work now in process. *Project Manager: Abraham Silvers*

R&D Status Report
NUCLEAR POWER DIVISION

John J. Taylor, Vice President

INNOVATIVE PROTECTION PRACTICES AT TMI-2

All nuclear power plants have radiologic protection programs. Such programs are mandated by federal law (10CFR20) and are based on NRC regulations and Regulatory Guides, *as well as on Institute of Nuclear Power Operations (INPO) guidelines. The TMI-2 cleanup program has presented an opportunity for exploring and implementing new approaches to radiologic protection and for using the extensive experience and technical resources of a wide spectrum of participants, including individual utilities, DOE, NRC, and EPRI.*

Complying with the comprehensive regulatory requirements for radiation protection offers both a challenge and an opportunity to nuclear power plant operators. A variety of innovative research and in-plant programs are being pursued to help them meet this challenge.

One key goal in EPRI's research, under the direction of the Engineering and Operations Department, is to develop and demonstrate techniques for reducing out-of-core radiation fields. NRC and DOE are also sponsoring dose reduction research. This status report, however, focuses on the work being done by EPRI's TMI-2 Site Office in reviewing the radiologic protection tools, techniques, and practices developed in the TMI-2 accident recovery (RP2558). The objective of this project is to identify successful TMI-2 developments that have potential applications at operating nuclear power plants.

The extensive contamination released to plant systems by the accident and the long-term efforts to decontaminate and defuel TMI-2 provide a unique laboratory for developing, testing, and perfecting specialized protection tools and techniques. Comparison of estimates of radiation exposure for cleanup (between 13,000 and 46,000 man-rems) with total actual exposure to date (approximately 3200 man-rems, at the time when about 50% of the exposure-related recovery tasks had been completed) indicates the success of the program at TMI-2. Although much of this success is a consequence of rigorous application of existing radiologic protection principles, some resulted from the development and application of unique tools and techniques. In cooperation with GPU–Nuclear Corp. and DOE, EPRI's TMI-2 Site Office staff is evaluating new principles, tools, and procedures that utilities could apply to solve radiologic protection problems or to improve their current programs at operating nuclear power plants.

Four basic elements compose the radiation protection programs at TMI-2, and this report highlights each of these areas.

- Radiation exposure program management
- Radiologic engineering
- Occupational radiation exposure measurement, tracking, and reporting
- Radiation protection training

Radiation exposure program management introduces the ALARA concept (as low as reasonably achievable) into the decision-making process at the management and supervisory level. Engineers generally consider dose management and ALARA objectives when deciding how to perform a task. However, with the increasing need for utilities to document ALARA evaluations at the management level, more utility managers are becoming involved in ALARA decision making.

GPU–Nuclear management at TMI-2 has allocated the necessary resources—funding, equipment, and training—to allow control of ALARA decisions at the department level. Briefly, the program has two functional levels. At the administrative level, each department involved in tasks resulting in or influencing occupational radiation exposure must publish annual objectives and goals. Management uses these goals to evaluate the department's success in maintaining ALARA personnel radiation exposures.

GPU–Nuclear has developed a procedure that determines which departments participate, whether a task or decision involves ALARA objectives, and how to carry out a decision analysis for the optimal approach. Managers use these written analyses to evaluate their departments' success in meeting goals and as documentation for NRC inspectors. Radiologic control personnel serve only as technical advisers to department managers in development of their annual dose projections and for technical review of ALARA decisions, the responsibility for which remains with the department managers.

At the training level, radiologic control personnel have developed a program for TMI-2 department managers. This program focuses on showing management how a job's scope affects radiation exposure and on describing decision analysis methods by which management can set its ALARA goals and achieve them.

Radiologic engineering is the task of controlling radiation exposure and contamination in a power plant by adequately evaluating and planning the performance of radiologic work. The extent of in-plant contamination after the TMI-2 accident provided the initial impetus for research to improve the available radiologic engineering tools. Among the generally applicable engineering developments being documented by EPRI's TMI-2 Site Office are analytic techniques to determine shielding requirements; improved tools for radiologic surveying, including special detectors and remote inspection robots; specialized surface decontamination techniques; integrated use of radio and video communications between the work teams and their support staff; the use of a real-time job-exposure tracking system; and the use of computer-generated area survey maps to help plan decontamination activities.

This latter development—the use of computer-drawn maps to expedite radiation surveys of specific plant areas—is just beginning to be fully utilized at TMI-2. Personnel use a computerized radiation mapping and ALARA planning system (RADMAPS) to generate accurate drawings of a component, system, or plant area that can then be marked with the specific locations for which radiation exposure data are desired. Having an accurate map of an area that clearly shows the major visual features (e.g., pipes, components, stairways) and the specific areas to be surveyed enables a health physics technician to concentrate on accurate measurement, thereby improving the quality of the survey data and reducing the survey time. This technique is possible at TMI-2 because a complete, computerized three-dimensional model of the reactor building and its contents was created from more than 900 as-built drawings. Although no utility could justify the cost of such a model merely for radiation survey purposes, combining it with such other tasks as recording weld identification maps, inspection results, calibration records, and plant modifications makes the cost of a three-dimensional model reasonable.

Occupational radiation exposure measurement, tracking, and reporting are fundamental to all power plant radiologic protection efforts. Dosimeters measure personnel exposure to ionizing radiation; staff members read those dosimeters, update workers' cumulative dose records, and prepare the radiation exposure reports required by the NRC. At TMI-2, R&D in measurement, tracking, and reporting was prompted by the large number of workers, the variety of tasks necessary for plant cleanup, and the presence of extensive beta contamination within the plant. In response, researchers developed a computerized system for tracking and reporting radiologic work and new dosimeters for measuring occupational exposure and beta contamination. Both developments are applicable to operating plants.

Beta contamination is a particular problem at TMI-2 because fuel failure during the accident released large amounts of radioactivity into the primary coolant, which subsequently contaminated large areas of the reactor and auxiliary buildings. Beta exposure concerns are not unique to TMI-2, however. Other operating nuclear plants must deal with in-service inspections, reactor coolant systems modifications, coolant spills, and handling ion exchange resins—all of which involve potential exposure to beta radiation. In addition, older plants may require repair or replacement of beta-contaminated major components, such as PWR steam generators and BWR turbines.

The large number of beta-emitting isotopes present on contaminated surfaces at TMI-2 means that the range of beta particle energies is unusually large. Because the specific beta particle energies must be known to accurately measure skin exposures, the TMI-2 cleanup requires a beta dosimeter capable of measuring a broad range of energies. Research projects conducted by both DOE and GPU–Nuclear produced compact thermoluminescent beta dosimeters that measure beta energy, can be used in mixed beta and gamma fields, and can be read with commonly available equipment.

The DOE dosimeter uses eight lithium-fluoride thermoluminescent dosimeter chips under aluminum shields of various thicknesses. The shields allow the measurement of the associated gamma dose and achieve the desired beta energy discrimination. Knowledge of the specific beta particle energies permits a more accurate determination of worker radiation exposure than does the alternative of estimating dose rates by using survey meters. Although the GPU–Nuclear dosimeter, developed in conjunction with Panasonic Corp., is proprietary, it is similar to the one developed by DOE.

Radiation protection training is an essential part of a utility's radiologic protection program. This training pays important dividends, as indicated by INPO's recent citing of more and better training of workers in radiation protection as the reason for the significant decrease in the annual collective exposure (53,900 man-rems in 1984, compared with 42,500 man-rems in 1985) at U.S. commercial nuclear power plants.

GPU–Nuclear has developed an effective and comprehensive radiation protection training program, which has helped to reduce radiation exposures during TMI-2 cleanup activities and at the company's operating plants. One method that has proved highly effective in the GPU–Nuclear training program is the use of subject modules. The company divides its General Employee Training course into modules by subject. Each module (e.g., ALARA concept, radiation exposure control, radiation work permits) is assigned to an individual—called the module owner—considered an expert in that subject area. The module owner is directly responsible for providing the learning objectives, writing lesson plans and instructor guides, maintaining student materials and training aids, maintaining a file of tests and test results, conducting ongoing evaluations of the course module (e.g., instructor and material effectiveness, updated subject information and material), and ensuring that all instructors present the course material in a standardized manner. Completed modules are reviewed and approved by the site training manager and the radiation training manager.

The modular training approach provides feedback through test results and highlights potential weaknesses in course development or instructor presentation. This method quickly corrects training deficiencies because it reveals the precise areas that need further development. Also, as a plant's training needs change (e.g., when a plant prepares to go from a construction permit to an operating license), the company can alter the modules to address the new status. The module owner provides the control point and the source of technical information to be used in course development. The instructors use their professional communications skills to ensure that trainees receive the knowledge they need, whereas the module owner, who is familiar with new and evolving aspects of the subject area, focuses on what is important to safety and how much detail is appropriate.

By following this total program, personnel in the TMI-2 recovery have been able to accomplish difficult tasks in difficult radiation environments while still effectively controlling exposure. Work at TMI-2 has also shown that a good radiologic protection program makes efficient use of personnel and results in improved cost control. Although all four elements have contributed to the success of the TMI-2 program, the key element has been management's direct involvement in establishing and implementing a vigorous program.

EPRI will continue its technology transfer responsibility at TMI-2 by monitoring the cleanup and disseminating pertinent information on tools, techniques, and the lessons learned to enhance the safety and efficiency of operating power plants. Specific information on the TMI-2 cleanup program can be obtained from Ray Schwartz at EPRI's TMI-2 Site Office, (717) 948-1076. *Project Manager: Ray Lambert*

CONTAINMENT INTEGRITY

One of the important issues in the degraded-core scenario evaluations made since the TMI-2 accident is the load-carrying capability of reactor containment buildings if overpressurized beyond design basis levels. To reevaluate the risk, given the benefit of knowledge gained from the TMI incident and post TMI research, utilities need a better understanding of how containments can be expected to behave if subjected to large, nonlinear deformations; this is in contrast to the oversimplified assumptions about containment capacity and failure modes that have been used in past risk assessments. This status report summarizes current views on containment behavior and describes the experimental and analytic efforts being sponsored by EPRI toward resolution of this issue.

The concrete containment buildings that surround nuclear reactor systems are major barriers against the release of radioactive material during accidents. Because of the importance of containments in the defense-in-depth philosophy used for plant design, they are designed as pressure vessels, in accordance with ASME code provisions, to withstand internal design pressures from postulated loss-of-coolant accidents. However, the accident at TMI-2 focused attention on the very unlikely "what if" scenarios known as degraded-core accidents. Such accidents go beyond design basis accidents and have been addressed in probabilistic risk assessments (PRA) like the *Reactor Safety Study* (WASH-1400).

One of the most important steps in predicting radioactive releases in a PRA is to determine the time the containment may be breached during an accident scenario and the rate of effluent release through the breach. The effluent would consist of air and other gases and would carry with it aerosols, such as entrained water (steam) and suspended solid particles (including radioactive debris from the degraded core). Clearly, if the entire inventory of the containment atmosphere is assumed to be ejected suddenly (as in WASH-1400), the later the release occurs, the better. The additional time would allow for aerosols to settle out of the atmosphere onto containment walls and floors, for radioactive decay of debris, and for emergency evacuation. For nonaerosol fission products, the additional time also helps to increase plate-out or wash-out.

If, instead, the containment inventory is released gradually through leaks, the resultant pressure relief would delay the occurrence of rapid releases and diminish (because of plate-out) the long-term release, thereby reducing the consequences of a degraded-core accident. The picture is further complicated because aerosols will tend to deposit along the inner surfaces of cracks, blocking leak paths.

Containment failure modes

Concrete containments are designed to be leak-tight. This is achieved mainly by (1) special design of penetrations for cabling, piping, and personnel and equipment entry, and (2) a ¼–⅜-in (6–10-mm) steel plate that lines the containment. Anchored to the inner surface of a reinforced or prestressed concrete wall, the liner prevents leakage through cracks in the concrete. In accordance with various industry codes, containments have been designed to remain leak-tight from design basis accident pressures that range from 15 to 70 psig (2.1–5.9 MPa), depending on containment type (e.g., PWR, BWR) and size. Before commercial operation, the containments are proof-tested at 1.15 times the design pressure with an allowable leakage limit $\leq$0.1%/d. On the basis of analyses by architect-engineers, these containments can withstand from 1.7 to 5 times the design pressure before the main reinforcement or tendons yield. From the design point of view, this yielding is considered to be a failure because relatively small increases in pressure lead to a large deformation of the containment building.

In response to the risk assessor's need to establish levels of containment capacity, the assumption has been made by architect-engineers that the liner acts as a membrane and remains leak-tight well into the large-deformation stage. This assumed liner behavior induces a sudden, gross rupture of the containment wall at or near the ultimate strength of the containment. Under this assumption, the containment would rupture as if it were a balloon. (Indeed, some tests of containment models performed with the concrete structure lined by a rubber bladder have demonstrated gross rupture modes.) This assumed failure mode has led the risk analysts to continue to assume a sudden and total release of containment gases, aerosols, and solid particles.

These oversimplified assumptions, based on linear design concepts, are almost certain to be misleading. In actuality, as the containment grows into the nonlinear, large-deformation stage, local liner failures can occur at corners, penetrations, anchors, and other areas of strain concentrations. Also, large deformations can potentially warp penetration openings, allowing leakage through seals and gaskets. Significant leakage is likely to occur during yielding of the main reinforcement. An overall hoop strain of only 1.5% allows the building to expand radially by about 1 ft (30 cm). Local failures and leaks may also occur at spots where wall movements are restrained by stiff, attached structures, such as piping, floors, or exterior walls. It has been calculated that a total leak area of only a few square inches is sufficient to limit peak pressure in a containment under degraded-core conditions and thereby prevent gross structural failures.

The only existing data on containment integrity came from scale-model tests in Japan and Canada, in which (as mentioned above) the mode of gross tensile failure was induced by the bladder used to load the structures. Also, because models were loaded hydraulically, no data on leakage rates were obtained. Some leakage data are available from Canadian and French testing, but these are for cracked concrete without a liner plate.

However, several pressurization tests of prestressed concrete reactor vessels have demonstrated premature failure by leakage at pressures well below the ultimate tensile capacity of the vessel walls. Typically, the vessels failed by the tearing of their steel liners near the welded joints at the intersections between the cylindrical walls and the flat roof or base.

In a related NRC-sponsored program, plans are being made by Sandia National Laboratories to pressurize a ⅙-scale model of a reinforced concrete containment with a steel liner. The model has been constructed and pneumatic testing is scheduled for early 1987. Penetrations and other areas of discontinuity were modeled as accurately as possible at the reduced scale. In these tests, leakage will be measured as a function of pressure. The NRC program also includes leak-testing of cable penetrations and hatches, as well as pressurization of scale-model steel containments.

EPRI research

EPRI's concrete containment integrity research is aimed at establishing the true failure modes and load-carrying capabilities of reinforced and prestressed containments under internal pressures beyond those for which they were designed (RP2712). The immediate goal is to provide utilities with a test-verified analytic tool for evaluating containment integrity. The ultimate goal, in conjunction with overall risk studies, is to characterize leak rates and radioactive releases as functions of pressure and time under various postulated severe accident scenarios. These scenarios involve such loadings as steam surges and hydrogen combustion, which can be treated as static because they vary slowly with respect to the dynamic response time of containments. Dynamic loads from potential hydrogen detonations or steam explosions have been hypothesized, but technical arguments have been advanced by the Industry Degraded-Core Program that such phenomena cannot occur in real-world situations.

The approach of EPRI's structural integrity research has been to conduct experimental and analytic work in parallel. To avoid the uncertainties associated with small-scale modeling of detailed structural response and leakage rates, EPRI's experimental program features tests of large- and full-scale segments of concrete containments. Work at the Construction Technology Laboratory (CTL) of the Portland Cement Association began with simple tests on structural elements to define material behavior. By progressing systematically to more prototypical tests of containment segments with penetrations and structural discontinuities, that work will provide data on leakage from realistic liner-failure mechanisms (RP2172-2).

In the first phase of EPRI's testing program, which was carried out in a preexisting NRC reaction rig at CTL, concrete slabs representing segments from reinforced and prestressed containment walls were tested under uniaxial and biaxial tensile loading. The slabs developed discrete cracks and stretched as much as 2%, which is equivalent to a 3-ft increase in containment building diameter. Also tested in the first phase were segments of a steel liner, which in a typical concrete containment are anchored to the containment inner surface to serve as a leak-tight membrane. The liner plates, containing butt welds or pipe penetrations, withstood up to 6% elongation without rupturing. The objective of the first-phase testing was to check out the testing procedure and to provide a data base for checking out concrete and steel liner behavior for the actual failure characterization to be investigated in phase 2.

The second phase of testing addresses

specifically the prestressed concrete containment failure mode characterization under internal overpressurization. A 50×10^6 lb (23×10^6 kg) multiaxial reaction rig, the largest of its kind, was fabricated at CTL for such an investigation. This rig is capable of testing full-scale, 3.5-ft (1.1-m) concrete containment wall segments with liner plates anchored into one side. The largest specimen tested contained a 30-in-diam (0.8-m) penetration sleeve and was 11×11 ft (3.4×3.4 m). Special apparatus for monitoring leakage was also installed to obtain information on leakage through the liner and through cracks in the concrete.

Three of the five tests completed in this program are of particular significance. The first was the test of a specimen that was 7×7 ft (2.2×2.2 m) thick with a weld in the liner plate running in the meridional direction along the centerline. A 6-in (15.2-cm) length of the weld seam was not welded. This simulated crack was to act as a calibrated leak path to determine air leak rates through the liner and concrete cracks during testing.

Biaxial loading was applied to the specimen. At the end of the test, it was found that the original 6-in-long liner plate crack had extended to 9 in (23 cm), and the crack width had expanded from zero to 0.38 in (1 cm). This tearing of the liner occurred in a very controlled manner, indicating interaction between the liner and concrete. The significance of this controlled liner tearing is that it contradicts the hypothesis of uncontrolled liner rupture. (Without the reinforced concrete behind the liner, the crack would have propagated unstably without arrest.) Also, it was found that the liner opening area controls the leak rate, indicating that the aggregate of the concrete cracks behind the liner either equals or exceeds the area of liner opening.

The second test specimen was 11×11 ft (3.4×3.4 m) and was 3.5 ft (1.1 m) thick; it had a large pipe-penetration sleeve at the center. The penetration was a 36-in-diam (1-cm), 1-in-thick (2.5-cm) pipe with a welded connection to the liner plate, which was 0.25 in (0.6 cm) thick. Testing included biaxial load, outward punching shear, and monitoring of air-leak rates.

The outward punching shear applied was 897 kips (4 MN) at the time when the maximum average strain in the hoop reinforcing was 2.5%. Up to this point, no measurable air leakage was noted. However, while the punching shear load was being removed, the pressure chamber behind the liner was completely depressurized, indicating that a liner crack had developed. After disassembling the test fixtures, it was found that there was a 16-in (41-cm) crack at the region of the sleeve-liner plate junction (Figure 1). Although the punching shear direction and magnitude applied in this test were somewhat artificial, the test showed that the ductile liner plate could crack before the reinforcing ruptured, owing to highly concentrated local strains. Consequently, it was demonstrated that through liner-concrete interaction in a region of discontinuity, leakage could occur because of a liner crack.

Figure 1 A 16-in-long crack at the junction of the steel liner and a simulated penetration opening in a prestressed concrete containment wall specimen. The specimen was subjected to biaxial and punching shear loadings typifying degraded-core overpressurization.

The third specimen that is of significance was a large-scale element representing a junction region of the wall and basemat of a prestressed concrete containment. Two highly localized discontinuous points in this specimen were the knee (wall-skirt intersection) and the basemat junction (skirt-basemat intersection).

Loading on the specimen was intended to simulate the bending moment and shear in the containment wall and also the axial load in the wall resulting from an internal pressurization. Because the test specimen could not duplicate the exact boundary conditions as they would occur in a full-scale containment, analysis was performed to define the loading sequence that would produce the desired behavior—one that corresponded to an internal pressurization of a full-scale containment.

Inspection of the liner after the test showed four small liner tears at the wall-skirt junction. These tears were in the discontinuity region where the liner was first joined at the end of the anchorage angles. At the skirt-basemat junction, there was a similar tear at one location where the liner plate joined with an anchorage angle. These localized failures at the discontinuities require very high strain concentration. The results show the potential for overpressurization-induced tearing of a containment liner at the wall-skirt and skirt-basemat junctions.

The tests performed to date demonstrate the following.

- The liner will crack in the discontinuity region if high strain concentration is induced.
- The liner will not crack if there is no discontinuity to induce high strain concentration in the liner.
- A preexisting crack or a crack initiated at the discontinuity region will not propagate, a result of interaction between the concrete and liner.
- Liner anchorage appears to play a critical role in concrete-liner interaction.

Consequently, it is highly probable that prestressed concrete containments subjected to structural deformation caused by severe core-induced overpressurization will develop leaks before they break.

In the next phase of this experimental effort, similar specimens will again be tested. However, they will represent reinforced concrete containments in which the reinforcement in the containment wall is much more dense and in which the liner anchorage design is slightly different from the prestressed one.

The analytic effort, conducted by Anatech International Corp. (RP2172-1), has focused on verifying and applying the nonlinear finite-element code ABAQUS–EPGEN (developed partially under EPRI sponsorship) for predicting the pattern of concrete cracking and its resultant interaction with rebars and liner that could produce local failure of the liner plate. Unlike many other applications of concrete under compression, the behavior of concrete containments is governed primarily by tensile stresses in the concrete-steel composite material. The challenge here is to develop a concrete material model, a rebar-concrete and liner-concrete interaction model, a liner crack criterion, and a finite-element idealization that can account for the overall response of the building and the local deformations leading to liner rupture or warping of penetrations. An important aspect of the code development work is the systematic benchmarking of the analyses against experimental program results. The end product will be a test-verified code for making realistic estimates of structural leak areas as a function of containment pressure. *Project Manager: H. T. Tang*

New Contracts

Project	*Funding / Duration*	*Contractor / EPRI Project Manager*
Advanced Power Systems		
Production of Superalloy Single Crystals for Gas Turbine Components (RP2382-4)	$204,000 9 months	Demetron, Inc./*C. Knauf*
Residual Fuel Oil Quality Criteria for Electric Utility Boiler Systems (RP2778-3)	$266,600 11 months	Riley Stoker Corp./ *W. Rovesti*
Biological Degradation of Coal (RP8003-6)	$75,500 12 months	University of Hartford/ *L. Atherton*
Coal Combustion Systems		
Characterization of Atmospheric Fluidized-Bed Combustion Solid Waste (RP718-9)	$101,500 6 months	Radian Corp./*E. Petrill*
Guidelines for Cycling Conversion of Fossil Fuel Units (RP1184-19)	$190,100 32 months	Gilbert/Commonwealth, Inc./*A. Armor*
Application of Coal-Cleaning Cost Model to Cleanability (RP1338-10)	$30,000 4 months	Resource Engineering, Inc./*J. Hervol*
Monitoring Fossil Fuel Plant Cycle Water Chemistry (RP2712-3)	$1,984,400 23 months	Sargent & Lundy/ *B. Dooley*
Leaking Underground Storage Tanks (RP2795-1)	$944,300 38 months	Roy F. Weston, Inc./ *M. Miller*
Urea NO_x Reduction Demonstration (RP2869-3)	$50,000 6 months	KVB, Inc./*D. Eskinazi*
Electrical Systems		
Conversion of EPRI Transient/Midterm Stability Package Software to IBM Mainframe (RP1208-10)	$56,400 4 months	Power Computing Co./ *J. Lamont*
HVDC Converter Station Electromagnetic Noise Study (RP1769-2)	$300,000 29 months	Ohio State University/ *S. Wright*
Data Base Management for Power System Planning Analysis: Phase 1 (RP2668-1)	$61,000 4 months	Carlsen & Fink Associates, Inc./*J. Lamont*
Production-Grade Version and Enhancement of Interactive Relay Coordination Program (RP2670-1)	$150,000 12 months	Power Computing Co./ *J. Mitsche*
Field Determination of Metal Oxide Varistor Characteristics (RP2747-2)	$680,000 24 months	Power Technologies, Inc./ *S. Lambert*
Energy Management and Utilization		
Analysis of Demand-Side-Planning Decision-Making Process (RP2224-9)	$123,300 10 months	Technology Research Corp./*D. Hu*
Planar Solid Oxide Fuel Cell Technology (RP2706-3)	$46,300 12 months	New Mexico Institute of Mining and Technology/ *R. Goldstein*
Marginal Utility Value in Industrial Complexes (RP2783-5)	$231,000 10 months	ICI–TENSA Services/ *A. Karp*

Project	*Funding / Duration*	*Contractor / EPRI Project Manager*
Development of a Variable-Speed Reciprocating Compressor Valving System (RP2792-3)	$135,000 9 months	Tecumseh Products Co./ *P. Joyner*
Field Verification of Residential Load Control Emulator (RP2830-2)	$210,500 15 months	Electrotek Concepts, Inc./ *L. Carmichael*
Electric Heating and Drying of Nonmetals (RP2893-2)	$74,100 5 months	Science Applications International Corp./*A. Karp*
Environment		
Environmental Effects of Ash Use (RP2796-1)	$394,400 18 months	Radian Corp./*I. Murarka*
CHOICE: Integrated Options Development and Risk Management (RP2807-2)	$100,000 10 months	Temple, Barker & Sloane, Inc./*D. Geraghty*
Nuclear Power		
Design Review and Quality Assurance Program for EQHAZARD Software (RP101-47)	$136,700 6 months	J. R. Benjamin & Associates, Inc./*C. Stepp*
Thermal-Hydraulic Models (RP1163-16)	$181,300 12 months	S. Levy, Inc./*R. Breen*
Japanese In-plant Radwaste Minimization Techniques (RP1557-25)	$37,900 6 months	JGC Corp./*P. Robinson*
Low-Power Digital Feedwater Control System Development (RP2126-7)	$383,600 24 months	Westinghouse Electric Corp./*B. Sun*
Transport of Cesium Iodide by Steam in a Radiation Field (RP2136-2)	$136,000 12 months	Atomic Energy of Canada Ltd./*R. Ritzman*
Measurements of pH and Corrosion Potential at Elevated Temperatures (RP2160-13)	$60,000 6 months	SRI International/ *C. Shoemaker*
Specification for Use of Alloy X-750 in LWRs (RP2181-4)	$33,900 7 months	Stone & Webster Engineering Corp./*J. Nelson*
Analyses of Large-Scale Seismic Experiment in Lotung (RP2225-16)	$103,200 15 months	EQE, Inc./*Y. Tang*
Direct Assay: Shield and Spectrum Calculational Method (RP2412-7)	$50,500 5 months	Battelle, Pacific Northwest Laboratories/*P. Robinson*
Physics Analysis for PWR Loss-of-Feedwater ATWS (RP2420-38)	$35,000 6 months	S. Levy, Inc./*J. Chao*
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Effect of Spatial Averaging on Earthquake Ground Motion (RP2556-22)	$71,000 10 months	Princeton University/ *C. Stepp*
R&D Staff		
Stress Corrosion Crack Merging and Its Influence on Remaining-Life Predictions (RP8002-2)	$97,000 25 months	University of Newcastle Upon Tyne/*B. Syrett*

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EPRI Project Manager: M. McLearn

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AP-4682 Final Report (RP1996-25); $25
Contractor: Southern California Edison Co.
EPRI Project Manager: F. Goodman

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EPRI Project Manager: A. Cohn

COAL COMBUSTION SYSTEMS

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CS-4548 Interim Report (RP1400-6, -11); $32.50
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EPRI Project Managers: C. Harrison, J. Hervol

Fossil-Fired Boiler Tube Inspection: Nondestructive Testing Guidelines
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Contractor: Southwest Research Institute
EPRI Project Manager: J. Scheibel

Coal-Handling System Problems at Gulf Power Company's Plant Crist: A Root-Cause Analysis
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EPRI Project Manager: L. Harry

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EPRI Project Manager: A. Karp

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EPRI Project Managers: P Fairchild, P. Joyner

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EPRI Project Manager: J. Guertin

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EPRI Project Manager: E. Altouney

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EA-4739 Final Report (RP2140); Vol. 1, $32.50; Vol. 2, $32.50
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EPRI Project Manager: E. Altouney

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EPRI Project Manager: T. Passell

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NP-4583 Interim Report (RP2295-2); $25
Contractor: UK Atomic Energy Authority
EPRI Project Manager: C. Wood

Hydrogen Water Chemistry for BWRs: Status Report on U.S. Development Program
NP-4592-SR Special Report; $25
EPRI Project Manager: R. Jones

BWR Fuel Rod Performance Evaluation
NP-4602 Final Report (RP510-1, -2); $32.50
Contractor: General Electric Co.
EPRI Project Manager: S. Gehl

ATHOS3: Computer Program for Thermal-Hydraulic Analysis of Steam Generators
NP-4604-CCM Computer Code Manual (RP1066-1); Vol. 1, $40; Vol. 2, $40; Vol. 3, $47.50
Contractor: CHAM of North America, Inc.
EPRI Project Manager: G. Srikantiah

ASME Code, Section XI, In-service Inspection of Nuclear Power Plant Components: 1984–1985 Revisions and Updates
NP-4615 Final Report (RP2057-5); $32.50
Contractor: Science Applications International Corp.
EPRI Project Manager: G. Dau

Decay Heat Measurements and Predictions of BWR Spent Fuel
NP-4619 Topical Report (RP2406-2); $32.50
Contractor: Battelle, Pacific Northwest Laboratories
EPRI Project Manager: R. Lambert

Chemistry Control With Morpholine at Beaver Valley Power Station
NP-4623 Interim Report (RP2647-1); $25
Contractor: NUS Corp.
EPRI Project Manager: T. Passell

Evaluation of New pH Control Agents for PWR Secondary Water Systems
NP-4624 Final Report (RP1571-7); $25
Contractor: Westinghouse Electric Corp.
EPRI Project Manager: T. Passell

Laboratory Examinations of Selected Tubes From Test Facilities of the Steam Generator Owners Group
NP-4625 Final Report (RPS302-12); $40
Contractor: Westinghouse Electric Corp.
EPRI Project Manager: C. Shoemaker

Steam Generator Tube Sampling: Feasibility Study
NP-4626 Final Report (RPS304-2); $40
Contractor: Babcock & Wilcox Co.
EPRI Project Manager: P. Paine

Stress Relief Cracking in Nuclear Pressure Vessel Steels
NP-4627 Final Report (RP2060-4); $25
Contractor: University of Pennsylvania
EPRI Project Manager: R. Jones

Simulated Void-Box-Capsule Charpy Impact Test Results
NP-4630 Final Report (RP1021-10); $25
Contractor: Fracture Control Corp.
EPRI Project Managers: T. Marston, T. Griesbach

Remedial Methods for Intergranular Attack of Alloy 600 Tubing
NP-4635 Final Report (RPS302-10, -13, -14); Vol. 1, $32.50; Vol. 2, $32.50; Vol. 3, $25
Contractors: Westinghouse Electric Corp.; Battelle, Columbus Laboratories; Babcock & Wilcox Co.
EPRI Project Managers: S. Hobart, C. Shoemaker, M. Angwin

Oxide Growth Mechanisms on Chromium Alloy Steels
NP-4647 Final Report (RP1171-2); $40
Contractor: Central Electricity Generating Board
EPRI Project Manager: C. Shoemaker

Effects of Oxygen, Copper, and Acid Chlorides on Denting Corrosion
NP-4648 Topical Report (RP1171-3); $25
Contractor: Central Electricity Generating Board
EPRI Project Manager: C. Shoemaker

Proceedings: Workshop on Thermally Treated Alloy 690 Tubes for Nuclear Steam Generators
NP-4665M-SR Special Report; $25
EPRI Project Manager: C. Shoemaker

Evaluation of the Toughness of Austenitic Stainless Steel Pipe Weldments
NP-4668 Final Report (RPT303-3); $25
Contractor: General Electric Co.
EPRI Project Manager: D. Norris

Survey of Domestic and Foreign PWR Experience With Morpholine in Chemistry Control by All-Volatile Treatment
NP-4671 Final Report (RPS306-18); $32.50
Contractor: NUS Operating Services Corp.
EPRI Project Manager: S. Hobart

Correlation of Tube Support Structure Studies
NP-4672 Final Report (RPS311-1); $32.50
Contractor: Atomic Energy of Canada Ltd.
EPRI Project Manager: M. Angwin

Crevice Hideout Return Testing
NP-4678 Final Report (RP699-2); $32.50
Contractor: Westinghouse Electric Corp.
EPRI Project Manager: C. Shoemaker

Recirculating Steam Generator Tubesheet Crevice Flushing Procedures
NP-4686 Topical Report (RPS309-1); $32.50
Contractor: Dominion Engineering, Inc.
EPRI Project Manager: L. Williams

Corrosion Evaluation of the PNS CITROX Process for Chemical Decontamination of BWR Structural Materials
NP-4687 Interim Report (RP2296-6); $25
Contractor: General Electric Co.
EPRI Project Manager: C. Wood

Evaluation of Flaws in Austenitic Steel Piping
NP-4690-SR Special Report; $25
EPRI Project Manager: D. Norris

Industrywide Survey of PWR Organics
NP-4698 Final Report (RPS306-12); $40
Contractor: Westinghouse Electric Corp.
EPRI Project Managers: C. Welty, S. Hobart

Electrochemistry and Corrosion of Alloys in High-Temperature Water
NP-4705 Final Report (RP2163-3); $32.50
Contractor: University of Leuven
EPRI Project Manager: D. Cubicciotti

Chemical Cleaning of PWR Steam Generator Sludge Piles
NP-4708 Final Report (RPS305-11); $40
Contractor: Combustion Engineering, Inc.
EPRI Project Manager: L. Williams

Behavior of High-Density Spent-Fuel Storage Racks
NP-4724 Topical Report (RP2062-11); $25
Contractor: Battelle, Pacific Northwest Laboratories
EPRI Project Manager: R. Lambert

BWR Cobalt Deposition Studies: Progress Report 2
NP-4725 Interim Report (RP2295-3); $32.50
Contractor: General Electric Co.
EPRI Project Manager: C. Wood

Seismic Hazard Methodology for the Central and Eastern United States
NP-4726 Final Report (RP101-19 to -24); Vol. 5, $55; Vol. 6, $47.50; Vol. 7, $40; Vol. 8, $47.50; Vol. 9, $32.50; Vol. 10, $40
Contractors: Weston Geophysical Corp.; Dames & Moore; Law Engineering Testing Co.; Woodward-Clyde Consultants; Bechtel Group, Inc.; Rondout Associates, Inc.
EPRI Project Managers: J. King, C. Stepp

Radwaste Sludge Removal and Packaging
NP-4730 Interim Report (RP2012-12); $32.50
Contractor: Battelle, Pacific Northwest Laboratories
EPRI Project Manager: R. Lambert

Radiation Effects on Lubricants
NP-4735 Final Report (RP1707-27); $25
Contractor: Robert O. Bolt
EPRI Project Manager: R. Kubik

Corrosion-Product Release in LWRs: 1984–1985 Progress Report
NP-4741 Interim Report (RP2008-1); $25
Contractor: Atomic Energy of Canada Ltd.
EPRI Project Manager: H. Ocken

PWR Radiation Control: Once-Through Steam Generator Studies
NP-4753 Final Report (RP825-1); $32.50
Contractor: Babcock & Wilcox Co.
EPRI Project Manager: R. Shaw

Operation of the EPRI Nondestructive Evaluation Center: 1985 Annual Report
NP-4755 Interim Report (RP1570-2); $32.50
Contractor: J. A. Jones Applied Research Co.
EPRI Project Manager: G. Dau

PLANNING AND EVALUATION

Capital Cost Estimates and Schedules for Coal-Fired Power Plants
P-4542 Final Report (RP1678-1-4); $100
Contractor: Bechtel Group, Inc.
EPRI Project Manager: R. Loth

R&D STAFF

Effects of Dynamic Strain on Crack Tip Chemistry
RP-4649 Final Report (RP2258-1, -3); Vol. 1, $32.50; Vol. 2, $25
Contractors: University of Newcastle Upon Tyne; Southwest Research Institute
EPRI Project Manager: B. Syrett

CALENDAR

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

NOVEMBER

5–6
Reducing Electricity Generation Costs by Improving Coal Quality
Indiana, Pennsylvania
Contact: Clark Harrison (412) 479-3505

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

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

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

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

17
Seminar: Flue Gas Desulfurization Maintenance Guidelines
Atlanta, Georgia
Contact: Robert Moser (415) 855-2277

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

18–21
10th Symposium on Flue Gas Desulfurization
Atlanta, Georgia
Contact: Robert Moser (415) 855-2277

DECEMBER

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

1–2
Seminar: Over/Under Capacity Planning Model
Chicago, Illinois
Contact: Hung-po Chao (415) 855-2622

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

3–5
1986 Fuel Supply Seminars
San Diego, California
Contact: Jeremy Platt (415) 855-2628

9–11
Utility Motor Reliability
Phoenix, Arizona
Contact: Jan Stein (415) 855-2390

FEBRUARY

19–20
State-of-the-Art Commercial Cool Storage
Denver, Colorado
Contact: Ronald Wendland (415) 855-8958

24–26
Workshop: Control Systems for Fossil Fuel Power Plants
Atlanta, Georgia
Contact: Murthy Divakaruni (415) 855-2409

MARCH

10–12
Symposium: Power Plant Pumps
New Orleans, Louisiana
Contact: Stanley Pace (415) 855-2826

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