The Rush for Transmission Access

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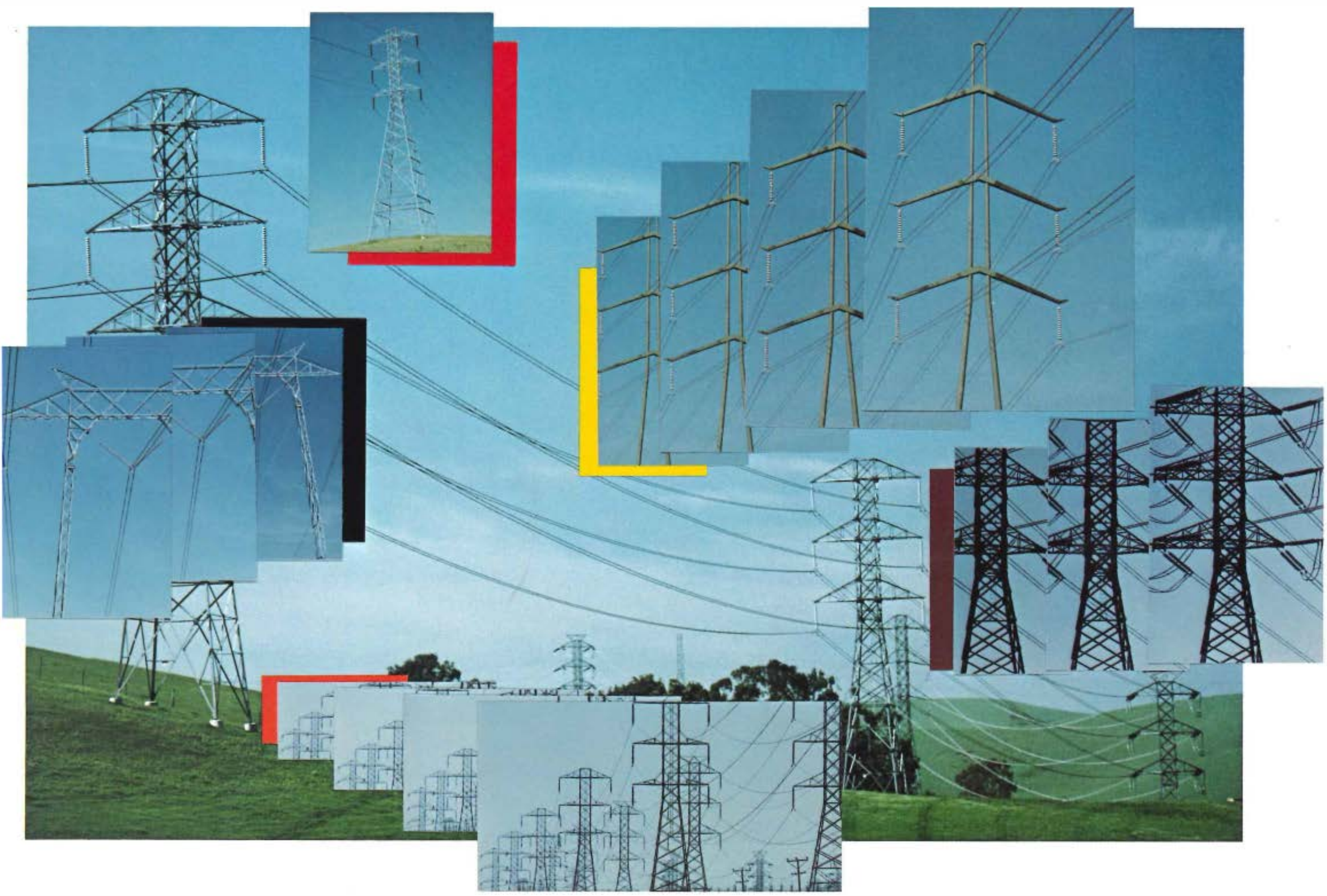

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Cover: Cogenerators, independent power producers, and Canadian utilities are pushing for more access to utility-owned transmission facilities as competition for the U.S. electricity market heats up.

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Wheeling: Realities on the Technical Side

Dougherty

The 1980s have brought substantial changes in the business climate for electric utilities. Many utilities are selling large blocks of power to other utilities, often located hundreds of miles away. In addition, cogenerators, independent power producers, and Canadian hydroelectric generators are all looking to secure a share of this country's electricity sales. As a consequence of competition among such suppliers, large industrial customers are beginning to shop around for their electric service.

The situation is simply expressed—more sources want to put power on the national grids than ever before. However, such new competitive opportunities, based on the idea of wheeling power from one place to another, carry with them new uncertainties. Not all entities have the same commitment to or responsibility for reliability of service. The most provocative question is who will have access to utility-owned transmission systems and under what circumstances. Much of the discussion of this topic must take place in the policy arena, as it has profound implications for the institutional infrastructure of the entire utility business.

A more basic concern centers on the technical side of things. Although the nation's transmission systems were originally designed to serve local loads, individual systems have been modified to permit utilities to exchange power among themselves for operational benefits. But these systems have not been designed for wholesale wheeling over very long distances. Still, the real constraints are likely to be institutional—the technical problems are manageable, although such broadened use of the transmission grids may not always be economical.

With new rights-of-way becoming increasingly difficult to obtain, one of EPRI's key goals is to find economical ways of increasing the use of existing transmission systems to meet demands of both the customer and the marketplace. Other EPRI work is examining the possibilities for increasing bulk transmission capabilities through application of technologies now in use and on the drawing board.

Policymakers have a challenging task before them on the volatile transmission access issue. By surveying and reporting how technical problems of bulk power transmission have been addressed or may be approached in the future, we hope to add input that will help to resolve the debate at hand.

John J. Dougherty

John J. Dougherty, Vice President
Electrical Systems Division

Authors and Articles

Young Iveson Hingorani Porcella Kennon Neal Compton Nelson

Network Access and the Future of Power Transmission (page 4) reviews many of the conflicting electrical and economic factors that inhibit use of transmission systems as common carriers, as well as research to increase the reliable capacity of those systems. Written by Taylor Moore, senior feature writer, with guidance from three EPRI staff members.

Frank Young, the manager of strategic planning since 1981, joined EPRI in 1975 as a transmission research manager after 20 years with Westinghouse Electric Corp., much of that time involved in UHV transmission research. Young has BS and MS degrees in electrical engineering from Stanford University and the University of Pittsburgh, respectively.

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Restoring Life to Acidified Lakes (page 14) reviews past practices and current research in lime treatment for restoring acidic lakes. Written by Michael Shepard, *Journal* feature writer, with assistance from EPRI's Energy Analysis and Environment Division.

Donald Porcella manages ecological research projects, in particular investigating the effects of electric power facilities on aquatic systems. He came to EPRI in December 1984 after six years with Tetra Tech, Inc., where he was responsible for research in the optimal use of cooling lakes. Before that he was on the civil and environmental engineering faculty of Utah State University for nine years. Porcella has a PhD in environmental health science from the University of California at Berkeley. ■

TICs: Directing R&D Information (page 22) traces the changing needs and perceptions that have shaped the roles of technical information coordinators at EPRI member utilities. Written by Ralph Whitaker, feature editor, aided by four coordinators and three EPRI staff members.

John Neal became EPRI's manager of member services in 1984 after 2 years as a regional representative. He was previously with the DOE for 7 years, and before that, he was with the Pratt & Whitney Division of United Technologies Corp. for 15 years, working on combustion turbine development. Neal has an MS in mechanical engineering from the University of Florida.

Olga Compton, manager of technical information distribution, came to EPRI in 1981 after five years as manager of the technical services center for Central Vermont Public Service Corp. Compton received an MS in information sciences at the State University of New York at Albany.

Burton Nelson, director of regulatory relations since 1980, has worked closely with an advisory committee of technical information coordinators since it was formed more than 2 years ago. His professional background also includes 11 years as a member of the Illinois Commerce Commission and 25 years in industrial management. Nelson has an MS in business administration from Northern Illinois University. ■

Groundline Repair for Wood Poles (page 28) reviews a newly available system for inexpensively repairing wooden utility poles that have decayed at the groundline. Written by John Douglas, science writer, with information from EPRI's Electrical Systems Division.

Richard Kennon has managed a program of overhead lines research since 1978. He joined EPRI in 1975 after nearly 23 years with Westinghouse Electric Corp., the last 5 years as manager of capacitor engineering. He has a BS in electrical engineering from the California Institute of Technology and an MBA from Indiana University. ■

High-voltage transmission lines crisscross North America in a kind of interstate highway system for electricity. Like its concrete and asphalt counterparts, this network of circuits includes freeways and turnpikes, major arteries, and local highways—each with a limited capacity for traffic. Also, as on the highways for motor vehicles, bottlenecks and closures can affect the flow of traffic far afield.

On many of the critical legs in this interconnected network of conductors, switches, and substations, it is rush hour all day long. Transmission lines bring large quantities of bulk power—in some cases, hundreds of miles from generating plants—to population and industrial load centers. But increasingly, these same circuits are being used for other purposes as well: to permit sharing surplus generating capacity between adjacent utility systems, to ship by wire large blocks of low-cost power from remote sites in mining states or hydroelectric regions to high-energy-cost areas, and to provide emergency reserves in the event of equipment or weather-related outages.

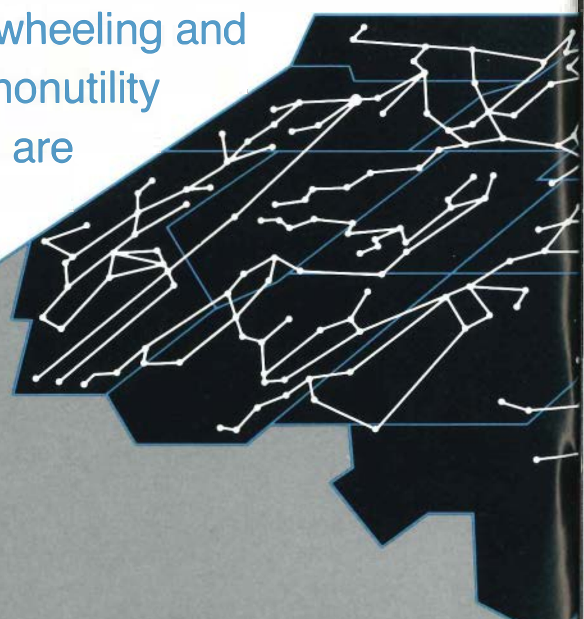
Recently, further twists have been added that many observers say will push transmission networks closer to their physical limits than ever before, possibly with noticeable consequences to electric service reliability. Recent laws and tax incentives have spawned a new class of nonutility electric generating entities, many of which would like to sell their power to the highest bidder, whether a utility, factory, or city, wherever it may be. On the demand side of the electric equation, an unevenly enjoyed national economic recovery and widening regional differences in generating costs are adding to competitive pressures, causing many large industrial and commercial users of electricity to shop beyond their local utilities for cheaper supplies as a way to reduce production costs and maintain competitiveness.

Together, these forces are converging on the nexus of today's modern power system: the transmission networks that link buyers, sellers, and utility grids. Such forces are also bringing to the fore of an already rich industry lexicon the terms *transmission access* and *wheeling*. Although interrelated, the terms are distinct and can have positive or negative connotations, depending on their context and whether one's perspective is that of a utility, an independent power producer, a consumer, a regulator, a policymaker, or an economist.

Nearly all utility customers are served directly or indirectly by some portion of the nation's interconnected transmission system; access in the context of the current debates relates to use of transmission facilities by parties other than the utility that built them. Wheeling refers to transmission by the local or other intervening utility systems of electricity generated by a third party to an ultimate consumer, either within or beyond the local service area, or to another utility.

From the perspective of utilities that

The pressures for wheeling and the emergence of nonutility electricity generators are among the many forces redefining how electricity is provided in this country. The pivotal question is who will have access to the grid's high-voltage transmission lines.



NETWORK ACCESS FUTURE OF POWER

own and operate transmission facilities, access to the network is something they want to continue to control, not only to preserve system stability, reliability, safety, and the quality of power, but also for obvious business reasons. Transmission-owning utilities would argue that they already wheel a considerable amount of energy through their systems to other utilities, including most of the municipal and rural electric cooperatives, as well as to other large integrated utilities. Existing transmission capacity, to some extent, was also intended to provide a margin for increased energy demand in the future, a margin for which present customers already pay in electric rates.

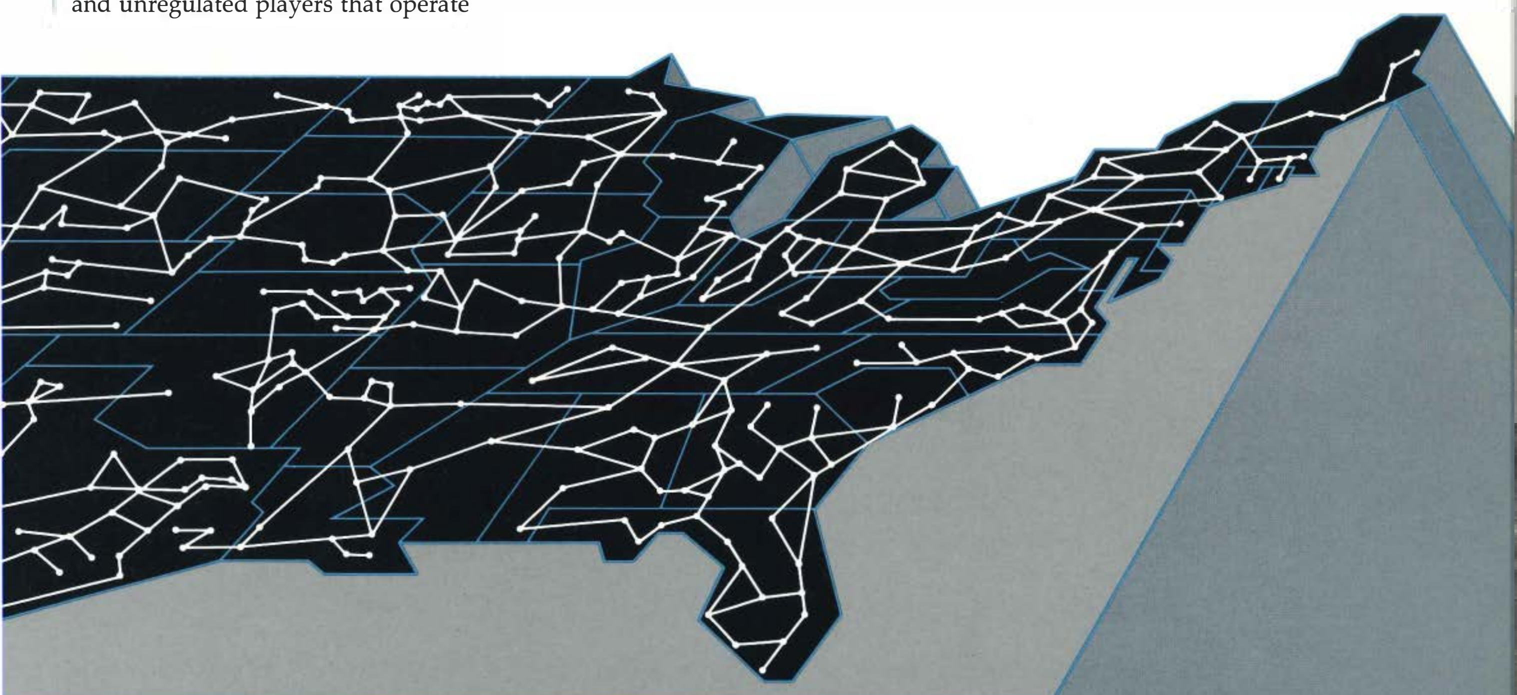
To those utilities that built and operate transmission facilities, there is good wheeling and bad wheeling—good, if between consenting, regulated utilities that agree on terms fair and beneficial to all parties; bad, if between regulated and unregulated players that operate on an uneven playing field under different rules. This latter form of wheeling, some economists have noted, could amount to wheeling money rather than energy. Wheeling is also viewed negatively to the extent that system security may be jeopardized or capacity for future growth in demand is depleted for near-term motives.

Against this backdrop of growing competition, as well as government and regulatory interest in promoting greater economic and technical efficiency in electric power production, EPRI has launched a special study of the technical limitations to transmission system operation. Undertaken at the request of the National Association of Regulatory Utility Commissioners (NARUC), the study is intended to identify R&D under way in the United States and overseas that holds the potential for eliminating or reducing bottlenecks and expanding transmission capabilities. It will complement an existing broad research effort to advance the state of the art in transmission system technology that is essential for maintaining a reliable and economical power delivery system in the future.

Network evolution

Most transmission lines were built solely to bring electricity from generating plants to nearby urban load centers.But in recent decades, utilities have extensively interconnected their systems and, in some cases, formed power pools to improve reliability by sharing generation reserves and to provide one another backup capabilities in the event of outages and emergencies.

Today, utilities and government power authorities in the United States operate some 135,000 circuit-miles (217,215 km) of alternating-current (ac) transmission lines, ranging in voltage



AND THE TRANSMISSION

INSTITUTIONAL PLAYERS IN THE TRANSMISSION ACCESS DEBATE

A large number of institutional players have a stake in the current debate over transmission access and wheeling. The issues affect all utilities, their relationships with one another, and their relationships with retail and wholesale customers. Three general groups of participants are involved: utilities that own transmission facilities; utilities, large industrial customers, and power producers that do not own transmission facilities; and the various state and federal regulatory agencies, Congress, and consumer groups with interests at stake. It is not yet clear how the conflicting institutional goals and concerns of these players will resolve themselves in the years ahead.

Investor-owned utilities Generally vertically integrated utilities that own and operate generation, transmission, and distribution facilities. They largely favor the status quo (maintaining control and priority use of transmission facilities), with safety, system security, and reliability as principal concerns. Some have surplus generating capacity, while others purchase part of their supply from other utilities. They want fair reimbursement for use of their transmission facilities.

Government-owned utilities Principally the Tennessee Valley Authority, Bonneville Power Administration, Western Area Power Administration, and Southeast Power Administration. They market and transmit power from federal dams and other generating plants to municipal utilities and rural cooperatives for distribution, as well as sell surplus power to private utilities. They also want a fair price for their services.

Municipal utilities Large municipals may own some transmission and generation capacity, but most are distributors only, relying on private utilities or government power authorities to sell and transmit power to them. Municipals want to be charged a fair price for transmission services.

Rural electric cooperatives Although some cooperatives generate as well as transmit power, most are distributors only; they depend on other utilities and government agencies for generation and transmission and want greater access to wholesale supplies.

Canadian provincial utilities Includes Ontario Hydro, Hydro-Quebec, Manitoba Hydro, and British Columbia Hydro. Canadian utilities export more than $1.5 billion of electricity to the United States (principally from Ontario and Quebec into New York and New England) and are pursuing agreements to transmit even more power in the future.

Cogenerators Large industrial and commercial customers, many of whom are generating much of their own electricity and selling the surplus to utilities. Many require backup power from the local utility. Some want to sell to the highest-bidding utility or large consumer and wheel power through local transmission lines.

Independent power producers Largely nonconsumers, including unregulated entities operating thermal, wind, and hydro generating facilities whose numbers are growing. Federal law requires local utilities to pay avoided-cost rates to such producers, but if those rates are low or if there is excess local capacity or energy, independent producers want to wheel their output to markets where it brings the highest price.

Large industrial customers Those who do not cogenerate and also face high electric rates want to control costs by shopping beyond their local utility for cheaper supplies from independent producers or other utilities. Many favor mandatory wheeling and access to transmission facilities. The Electricity Consumers Resource Council represents many large industrials in the transmission access debate.

Congress and federal agencies The Federal Energy Regulatory Commission is the focus on the national level of debate on transmission access and wheeling. Congress may extend limited FERC authority to order wheeling. The Rural Electrification Administration represents cooperatives who want less-restrictive access to transmission capacity. DOE has studied more-competitive rate structures for wholesale electricity pricing and supports limited deregulation of interutility power transactions.

State regulators The National Association of Regulatory Utility Commissioners has indicated support for more wheeling and regional coordination. Some state utility commissions have ordered wheeling in certain cases. NARUC has asked EPRI and the National Regulatory Research Institute to study the technical and the economic aspects, respectively. The National Governors' Association has also been a center of debate between resource-rich and energy-short regions.

Residential and commercial customers Many could face higher electricity rates if industrial customers leave the local system to cogenerate or purchase cheaper energy elsewhere and utilities have fewer customers from whom to recover costs. In some respects the interests of residential and small commercial customers coincide with those of large transmission-owning utilities, but they are less clearly represented than other participants in related policy debates.

from 230 kV up to 765 kV. Another 20,000 circuit-miles (32,180 km) could be added by 1995 if all lines now under construction, committed, or planned by utilities are actually built.

From a power system planner's perspective of maintaining system reliability, efficiency, and safety, installing new transmission capacity might be the preferred solution to the growing demand for transmission services. But the substantial delays and opposition most utilities encounter when attempting to build new capacity make this option costly and uncertain. New high-voltage lines can cost up to $750,000 a mile and take from five to seven years, or more, to complete. Moreover, increasing numbers of independent power producers add to uncertainties over whether there will be adequate transmission capacity to handle the growth in both generation and energy demand.

An upward trend in transmission line voltage ratings, which translates to greater power-carrying capacity, has made possible the evolution of today's modern power systems. The earliest circuits in the late nineteenth century involved voltages up to about 10 kV. As electricity use and loads increased and as power plants were sited farther from load centers, utilities expanded transmission capacity by overlaying networks of higher voltage. Hydro-Quebec introduced the first 735-kV lines in North America in the mid 1960s, followed in 1970 by the first 765-kV lines, built by American Electric Power Co. in the Ohio River valley.

The highest rated transmission lines (the freeways of the earlier analogy) are used for long-distance transmission, while those of intermediate voltage link local distribution systems through substations and transformers that step down the voltage even further for distribution to ultimate consumers.

Virtually all the electricity generated in the lower 48 states and in Canada is transmitted over four large integrated bulk power networks: the Hydro-Quebec system; the Eastern Interconnection, which covers most of the rest of the continent east of the Rocky Mountains; the Texas Interconnection (legacy of a traditional independence); and the Western Interconnection, which stretches from the Mexican border to the northern edge of British Columbia and Alberta.

In the conterminous United States, the transmission lines of the last three networks form the main arteries of no fewer than 153 separate power control areas representing either individual utility service areas or those of power pools. In each control area, loads and generator output are carefully balanced, typically at control, or dispatch, centers. Here powerful computers and system operators work around the clock, monitoring and analyzing system conditions for problems and adjusting (in most cases, automatically) the generators to produce more or less electricity as customer demand rises or falls, second by second.

The 1973 oil embargo intensified economic incentives for bulk power transfers in which lower-cost fuels from one region displace energy required by oil-short or oil-dependent utilities in another by means of high-voltage transmission. The practices of economy interchange and power wheeling through intermediate utility systems have since grown steadily as a result of widening regional differences in fuel costs, as well as surpluses and shortages of generating capacity in certain regions. Contractual arrangements have evolved for handling bulk power transactions on long-term (up to 30 yr), medium-term (2–15 yr), short-term (1 wk–2 yr) and spot market (1 h–1 wk) bases.

Utilities in the Northeast rely increasingly on imports of electricity from Canada; systems in the Southeast transfer large amounts of power within the region; Middle-Atlantic states import significant quantities from the Central United States; and the Northwest transmits vast amounts of hydro-generated energy to the Southwest over the massive 850-mi Pacific Intertie.

According to industry trade groups, in 1981, for example, about 20% of all electricity generated by private utilities was sold to other utilities through bulk power and economy interchange agreements. In the same year, more than 7% of all electricity sold to ultimate consumers was wheeled through one or more intervening utility systems. According to one estimate, during the decade 1971–1981 electricity wheeling increased by nearly 150%, compared with only a 42% increase in total electric sales.

Although such transfers have helped to keep electricity rates lower, they have also added greatly to the burden on transmission facilities and enlarged the coordination chores of control center computers and operators by nearly an order of magnitude.

Power flow

Greater use of transmission systems for economy interchange and wheeling highlights the relevance of certain laws of physics that constrain the ways the system can be used. Individual circuits are operated as part of a large network, which brings into play Kirchoff's laws of parallel or loop flow. Under these principles of electricity, current does not take a single path, but divides along multiple parallel paths having different carrying capacities in a way that is proportional to the impedance of all the available paths. In the highway analogy, when traffic backs up on a busy freeway, commuters can take alternative, more-circuitous routes, so that a number of paths share the traffic flow.

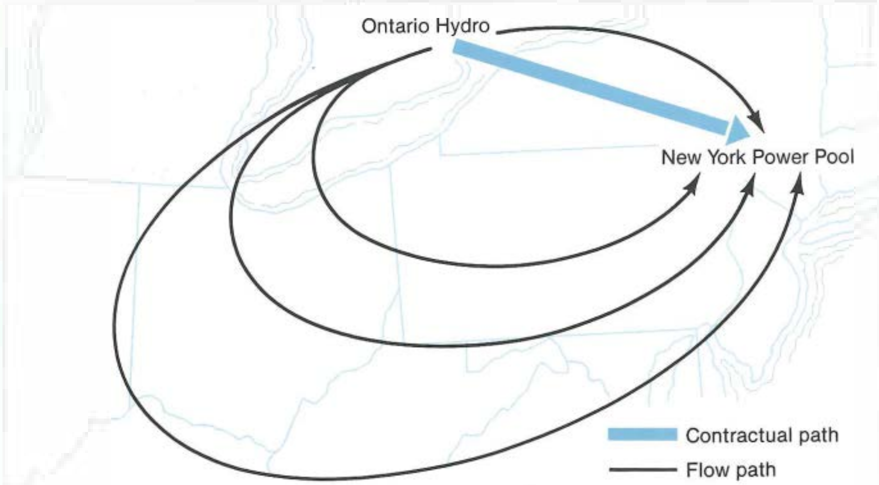
The electrical phenomenon of loop flow means, for example, that if Ontario Hydro is transmitting 1000 MW to the New York Power Pool, only 500 MW of power may actually flow over lines directly linking the two systems; the other 500 MW may flow in three other parallel paths through utility systems in Ohio, Kentucky, West Virginia, Virginia, Maryland, and Pennsylvania before registering on meters in New York.

Thus, actual paths of power flow can be quite different from the contractual paths. What may appear on paper to be a simple transaction between neighboring utilities can, in fact, require significant coordination with numerous other nearby systems. Imports of low-cost hydroelectric power from Canada into the Northeast can affect line loadings as far south as the Virginias and Carolinas. Utilities routinely accommodate the complexities of loop flows, but the prospect of substantially increasing the loop-flow numbers and schedules with more wheeling and third-party generation causes many utilities serious concern, particularly with respect to system stability.

Another technical factor that bears on wheeling involves the inevitable loss of an increasing fraction of the power flowing on a circuit as it travels over greater distances. Additions of current on a circuit that is already heavily loaded can result in electrical losses several times a circuit's average losses. More wheeling and competition may lead to a need for closer accounting of line losses, as well as difficulties in allocating their costs to all users of a circuit.

At long distances of transmission, thermal limits of conductors, voltage support, and stability limits are the dominant constraints on circuit capacity. At the distribution level of circuits, the effects of low or dropping voltage are seen when lights dim or motors stall. At the much higher voltage levels of transmission lines, voltage can be affected by the sudden presence or absence of generation sources and large loads, as well as by their physical location in the network's configuration.

System stability depends on the precise synchronism of all rotating generators. A disturbance, such as a circuit fault or the sudden loss of a generator, can cause other generators to accelerate and pull out of synchronism, with a resulting precipitous drop in power output. At the extreme of a large cascading instability, the effect is a collapse of the electrical network.



Loop Flows in Transmission Networks

The flow of current in interconnected transmission systems divides along multiple parallel paths in inverse proportion to the impedance of all available circuits. Because of this characteristic, the actual paths of current in a simple power transaction can be much more extensive than the contractual path, requiring coordination and planning by numerous intervening utility systems in addition to those selling and buying. For example, New York Power Pool's purchase of 1000 MW from Ontario Hydro can affect transmission line loadings in several nearby states; lower network impedance in those states may cause 500 MW of the desired purchase to flow over lines other than those directly linking Ontario Hydro and New York. Such loop flows can limit the ability of intervening systems to make additional transfers.

Reliability is of paramount concern to regulated utilities, which have a legal obligation to provide electric service. Memories of the widespread power interruption in 1965 that darkened much of the Northeast and the 1977 power failure in New York City are still familiar. One result of those events is that transmission lines are often operated at less than their maximum rating in order to provide reserve capacity for maintaining reliable service in the face of generator outages or the loss of some transmission circuits. But in recent years, utilities have been maintaining lower margins of reserve transmission capacity to take advantage of the growing opportunities for economy exchange.

The safety of equipment, utility personnel, and the public is an overriding concern that figures in transmission issues. "Generally, higher loading of transmission circuits also means higher switching overvoltages and overcurrent stresses in and around the transmission route," notes Narain Hingorani, director of the Transmission Department in EPRI's Electrical Systems Division. "For whatever form of power transaction, someone must take responsibility for ensuring that safety is not compromised."

Recent developments

In some respects the utility industry's interconnected transmission lines form the largest, most complex, and most dynamic technologic system in the nation. This is true not only in terms of the physical facilities, their geographic scope, and the cumulative investment they represent but also in terms of the numbers of players and their sometimes conflicting interests in the face of myriad economic, regulatory, and political forces at work on local, state, regional, and federal levels. The economic and institutional environment surrounding the operation of transmission systems is itself becoming increasingly dynamic. Consider a few examples.

Firms in key energy-intensive industries, including paper, chemicals, and petroleum production and refining, are increasingly turning to cogeneration and self-generation of electricity in response to rising prices and growing competitive pressures. The Public Utility Regulatory Policies Act (PURPA) of 1978 requires utilities to purchase the energy from local cogenerators and other small power producers at rates roughly equivalent to the cost of utility-generated power that is avoided by such alternative production. EPRI estimates that nonutility generating capacity could amount to 30,000–60,000 MW by 2010—over half of it from cogeneration, with the rest coming from other third-party producers, such as wind farms and small hydro projects.

Cogeneration is of great interest to utilities in that it both reduces demand and provides a source of electricity that is usually not under their operational control. With most cogeneration projects in the capacity range of 100 MW or less, the number of potential new users of transmission capacity could increase by 600 or more over the next 25 years, a figure that is nearly a fifth of the approximately 3200 diverse organizations that already sell electricity in this country.

These newcomers will not be evenly spread around, either; they will probably remain concentrated in a few regions: the Gulf Coast, the West Coast, and the Northeast. Some utilities already have dozens of cogenerators supplying power to the grid; fully one-quarter of the electricity that moves on one Gulf Coast utility system is from cogeneration. As the numbers of independent producers increase, pressures will grow to transmit more of their production to capacity-short utilities or to those with higher avoided-cost rates elsewhere.

Meantime, nongenerating industrial users of electricity are becoming an increasingly potent and vocal force in response to higher energy costs and stiffening competition. Some have called for the creation of industrial energy cooperatives as a means of lowering costs through joint purchases and ventures, as well as for new laws to require utilities to wheel electricity to those cooperatives.

Imports of mainly hydroelectric power from Canada to utilities along the northern tier of states totaled $1.5 billion in 1984. Although imports are not expected to play as important a role in national energy supply as cogeneration, they are still growing and new agreements for even more imported power are being pursued by parties on both sides of the border. Northeastern utilities are attempting to increase transboundary transmission capacity just to take advantage of current import opportunities, not to mention those expected in the future.

Imports, cogeneration, other nonutility power production, and interutility economy exchanges have led to near-maximum loading of transmission lines in certain regions. The North American Electric Reliability Council (NERC) reports, for example, that the most limiting bulk power transmission facilities in the Middle-Atlantic region of Pennsylvania, New Jersey, Maryland, Delaware, and the District of Columbia were loaded at 97% of capability for the last several years. Likewise, the Pacific Intertie, part of the 11-state transmission network west of Texas and the Rocky Mountains, operated at 92% of maximum capability in 1984.

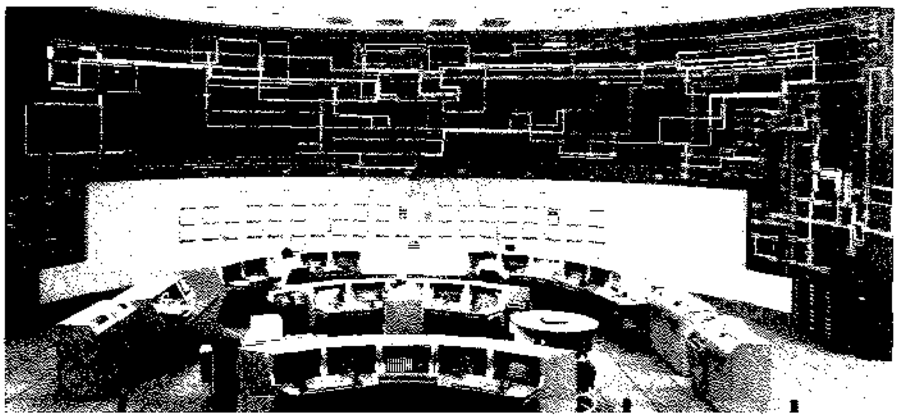
To accommodate such higher loadings, utilities have been exploiting transmission capacity reserve margins, and power systems are growing increasingly vulnerable to disturbances that can affect reliability. In the opening statement of its *1985 Reliability Review*, NERC warns that because of shrinking generation and transmission capacity reserves, it "expects the reliability of electric supplies to decline over the next 10 years."

Despite such warnings, a belief persists in policy and regulatory arenas affecting the utility industry that transmission capacity around the country is not being used to the fullest possible extent and more wheeling could reduce or delay the need for some of the additional generating capacity that will be required to meet demand growth in the future. Moreover, access to transmission facilities is seen in some circles as the statutory sine qua non for more competition in bulk power markets. But, as other observers have noted, while it may be true that greater competition in the electricity supply industry will lead to more wheeling, it does not necessarily follow that more wheeling will lead to a more efficient market in electricity.

Significant developments in recent years at the Federal Energy Regulatory Commission (FERC), which has ratemaking and other authority over all interstate and wholesale power transactions, have made it a focal point for much of the increased interest in transmission issues. Since 1983 the commission has experimented with limited deregulation of bulk power sales and rates in the Southwest, while its ongoing formal inquiry into pricing in wholesale power transactions has generated a multitude of commentaries from all quarters inside and outside the utility industry.

First-year results from the Southwest bulk power experiment indicate that little additional wheeling occurred despite the removal of certain regulatory price props; most of the wheeling that did occur was already covered under existing interutility agreements, according to the commission.

To some extent, FERC's moves have been prompted by repeated, but largely unsuccessful, efforts in Congress to substantially broaden the commission's limited authority to order wheeling as



NYPP control room

Power Pools and Economy Exchange

In some parts of the country, utilities have formed power pools to improve overall reliability and economic efficiency through sharing of generation resources via transmission lines.

Some pools operate in a tight configuration in which a central control center coordinates generation dispatch and communication between members. The New York Power Pool (NYPP), for example, coordinates virtually all New York's energy demand through its seven investor-owned utility members and the public Power Authority of the State of New York. NYPP's operations control center near Albany monitors the status of over 10,000 miles of transmission circuits throughout the state, as

a prelude to some type of legislatively mandated open access transmission policy. Congress's Office of Technology Assessment has been asked to conduct a broad study on technical impediments to increased wheeling, and at least one House subcommittee plans hearings on the subject in the current session.

Constraints on FERC's authority to order wheeling stem from the 1935 Federal Power Act and the 1978 PURPA amendments to it. In the main, the law relies on voluntary coordination among utilities to ensure low-cost, reliable service. FERC has no authority to order wheeling to retail customers and only limited authority to order wholesale power wheeling for PURPA-qualifying facilities or, possibly, as a remedy for anticompetitive conduct. PURPA amendments further require FERC to find, on issuing a wheeling order, that it "would reasonably preserve existing competitive relationships" among the affected utilities.

Separately, under antitrust provisions of the 1954 Atomic Energy Act, the Nuclear Regulatory Commission has imposed some wheeling obligations as conditions for issuing nuclear plant licenses. The federal courts also have vague powers to order wheeling under the Sherman Antitrust Act, although the legal uncertainties have inhibited most utilities from arbitrarily denying wheeling services.

On the state level, utility regulatory commissions have certain authority over intrastate wheeling and exclusive authority over retail rates, and they are showing an increasing willingness to mandate wheeling under some circumstances. Wheeling orders have been issued in individual cases in Texas and Florida and are under active consideration in New Jersey and other states. At least one state, Connecticut, has passed a mandatory intrastate wheeling law; many states have established task forces to consider wheeling issues, as has the National Governors' Conference.

State commissions are also forging ahead on transmission issues through their association, NARUC. Andrew Varley, chairman of the Iowa State Commerce Commission and head of NARUC's electricity committee, has given the subject high priority. NARUC's study, according to Varley, will address four basic questions: Is the best use being made of the existing transmission system? What and where are the physical constraints on the system? To what extent could an integrated direct-current (dc) system economically improve transmission capabilities? What is a proper pricing mechanism for wheeling power?

To carry out the study, NARUC last year called on EPRI and the National Regulatory Research Institute in Columbus, Ohio, for assistance. NRRI has undertaken an examination of the economic and regulatory principles involved in the pricing of power and wheeling services. EPRI is concentrating on identification of ways to eliminate transmission bottlenecks and increase transfer capabilities. Both groups will report periodically to NARUC and will issue formal reports for broad distribution throughout the industry at the conclusion of their studies in 1987.

One of the key issues under study by NRRI is whether a marginal-cost-based method of pricing transmission services that more accurately reflects the incremental cost of adding new capacity is a more appropriate and economically efficient price signal mechanism than the historic average-embedded-cost method that is now used by the industry and regulatory agencies.

EPRI's role

For its part EPRI has launched a comprehensive study to identify the root causes of transmission limitations and state-of-the-art technical solutions commonly used by U.S. and foreign utilities. In addition, the study will describe such technical implications as system stability and fault current effects of multiple third-party transmission ac-well as conditions in the neighboring New England Power Pool, Pennsylvania-New Jersey-Maryland Interconnection, Maritime Pool (New Brunswick and Nova Scotia), Hydro-Quebec, and Ontario Hydro.

In other areas power pools are more loosely configured, with each utility maintaining its own dispatch control center but in close coordination with neighboring utilities. Florida utilities, for example, participate in a state electricity brokerage arrangement through the Florida Electric Power Coordinating Group in which a common data base tracks available surplus capacity and energy for spot market transactions. Utility dispatchers, like those in Florida Power Corp.'s energy control center, are able to quickly determine willing buyers and sellers.

Florida Power Corp. control room

cess, provide the perspective of major power equipment manufacturers and utilities, determine the practicality of novel solutions beyond those now used, and outline the R&D needed to bring the best and most feasible solutions into useful utility application.

To meet at least part of the task—that of identifying work already aimed at eliminating bottlenecks and increasing capabilities—the study team has not far to look to find much of the leading edge. Since the Institute's founding, a principal focus of the Transmission Substations and Power Systems Planning and Operations programs in EPRI's Electrical Systems Division has been to advance the technology (both hardware and software) related to bulk power systems.

In contrast with typical EPRI research carried out by contractors, most of the analysis for the special study is being conducted by EPRI staff under the direction of Frank Young, manager of strategic planning. Utility perspectives will be gathered in a series of field interviews. A steering committee drawn from EPRI's Electrical Systems, Energy Analysis and Environment, and Planning and Evaluation divisions has been established to guide the effort.

"The principal focus of this study is technical, but the work must be performed within a framework that recognizes a changing business environment for electric utilities," explains Young. "It will not focus on the practices of a particular utility but will present a broad view of both the standard and the unique ways used by engineers to address the problem of increasing transmission capabilities."

The primary technical problems to be considered involve the physical apparatus of power transmission, the control of power flow, and the protective devices and procedures for increasing power flow on existing circuits. Upgrading and compacting overhead lines for maximum use of rights-of-way, developing lower-cost underground cables, and extending the life of existing equipment will also be examined.

On the equipment side, improved components for dc transmission are also being pursued. Dc systems are seen as a promising technical option for expanding transmission capacity because the flow of current is more easily controlled. Some 1750 mi (2815 km) of dc circuits are already used in certain areas of the United States for point-to-point transmission or as buffer connections between power systems that are not synchronized.

Key technical achievements already made in dc technology involve circuit breakers, control systems, lower-cost terminals for converting dc to ac or vice versa, and highly reliable solid-state valves consisting of light-triggered thyristors. Recent successful testing of an EPRI-developed dc circuit breaker, for example, has brought the possibility of multiterminal dc grids to reality.

Other research has focused on the development of better tools for engineering analysis and design. EPRI's microcomputer-aided engineering software package, the TLWorkstation,* is already being used by many utility engineers to analyze and design uprated or new, more-powerful lines and the stronger towers they require. The Transmission Line Mechanical Research Facility in Texas fills a key role as a physical test-bed for new tower and line designs. And recently, the turnover by General Electric Co. to EPRI of the High-Voltage Transmission Research Facility in Massachusetts adds an important laboratory to EPRI's research centers. The facility allows EPRI to assist member utilities in solving immediate problems related to the safe operation of existing circuits, as well as upgrading or uprating ac and dc lines.

The state of the art in ac transmission has also been advanced, for example, in successful demonstration last year by Southern California Edison Co. of a subsynchronous resonance damping

*TLWorkstation is an EPRI trade name.

device. Called the NGH–SSR, it enables extra-high-voltage lines (500 kV and greater) to be operated closer to theoretical limits with series capacitors without the risk of damaging generators by possible low-frequency feedback from the network.

The higher the voltage on a transmission circuit, the greater its power transfer capability. But if a circuit is overloaded above its current rating and the thermal limits of the metal conductor are exceeded, the line may overheat and sag below safe levels. Possible new directions for R&D include semiconductor-based phase-shifting transformers, tap-changers, and series capacitors—devices that can give utilities greater control over ac power flow by increasing or decreasing line impedance and phase angle.

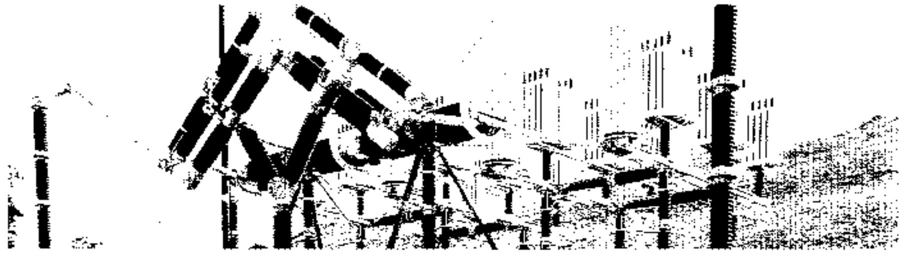
EPRI is also conducting a substantial R&D effort to develop and demonstrate microprocessor-based digital control and protection systems for transmission circuits and substations. "Such systems will have superior protection and control capabilities," reports Hingorani. "Their self-checking features will provide immediate information on hardware failures without false tripout or misoperation when called on. They will therefore reduce the number of outages and lead to improved transmission system performance."

Ultrahigh voltage (UHV) ac lines of 1000–1500 kV and dc lines of ±1000–±1200 kV have also been considered in recent times as one route to increasing transmission capacity. But reduced load growth and environmental concerns, including noise, radio interference, and field effects—in addition to the difficulties often encountered in siting new lines at present voltage ratings—have dampened expectations for their early use. Despite the need of many utilities today for technical options for line uprating and maximizing right-of-way corridors, EPRI believes that a need to use UHV circuits is unlikely before the year 2000.

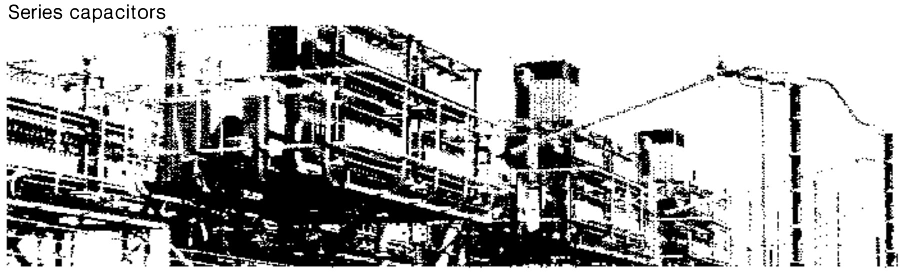
Technical Aids and R&D

EPRI develops hardware and analytic tools that help engineers manage and increase power flows on transmission lines. Successful testing of high-voltage direct-current (HVDC) circuit breakers makes possible multiterminal dc grids that offer greater current flow control than does conventional alternating current and are viewed as an option for strengthening intersystem transmission ties. Series capacitors and phase-shifting transformers (devices that increase or decrease effective line impedance and thus permit more or less power to flow over individual circuits) could become candidates for R&D to improve performance and reduce costs. Series capacitors can be used with an EPRI-developed subsynchronous resonance damping device to transmit more power on existing circuits. EPRI also sponsors R&D of computer codes and analytic methods for studying the effects of changes in system configuration or operating conditions.

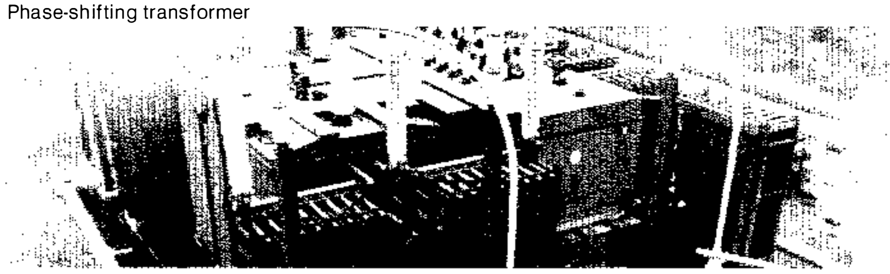
HVDC circuit breaker



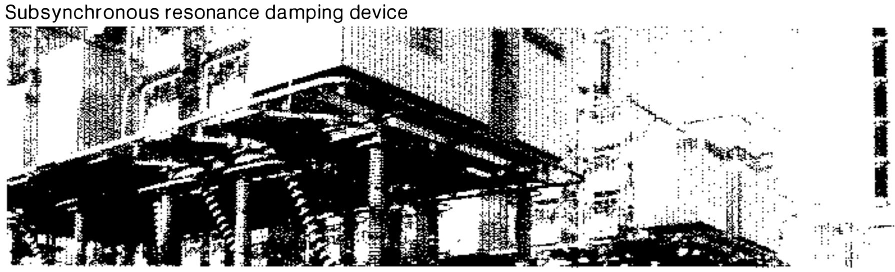
Series capacitors



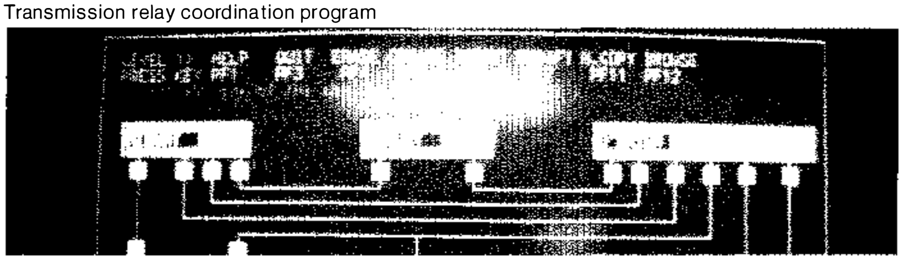
Phase-shifting transformer



Subsynchronous resonance damping device



Transmission relay coordination program



In the realm of systems operations and planning, increased power transfers will heighten the need for better ways to precisely measure system capabilities and display this information in real time to the operators. Despite reasonable consistency across the country in the engineering approach to measurement, it is nonetheless a complicated analysis involving such specific technical information as conductor temperature and degree of tolerance for faults and disturbances (e.g., lightning). There is substantially less consistency, however, in criteria for determining the actual loading on a system over time.

Better computer-based tools that can tackle the growing analytic requirements of system planners and operators continue to emerge. A first-of-a-kind transmission system reliability program is moving from prototype to production grade. Codes for analyzing the integration of multiterminal HVDC transmission into large ac systems will soon be released for utility use. A recently completed program, TRADE, is being used by the EPRI contractor to analyze transmission access conditions in an eastern state.

Meantime, the initial phase has been completed in a project to explore the application of concurrent or parallel computer microprocessor architecture in power system reliability analysis. "EPRI-funded work at Northwestern University and elsewhere has shown the concurrent processing approach (now emerging as the next generation of computer systems) to be feasible and most likely to be very cost-effective for reducing the computation burden and boosting the speed of power system simulations," comments Robert Iveson, manager of the Power Systems Planning and Operations Program. EPRI is pursuing actual tests of such multiprocessor architecture, including the Intel hypercube design, in realistic power system environments.

More-advanced telecommunications technology may also be needed to handle the increasing amounts and types of data on system conditions required by operators on a continuous, real-time basis. Major utilities already have extensive networks for interutility telecommunications that employ a host of technologies, including radio signals, microwave satellite transmission, and transmission line carrier signals.

Many utilities around the country have begun installing high-speed fiber-optic networks for communications between generating plants and operations centers, as well as for providing more real-time data on system conditions to neighboring utilities. But, as Iveson points out, "data communications requirements posed by the addition of multiple third-party users of transmission systems may outstrip the capabilities even of fiber optics. It will soon become more important to achieve very high data transmission rates and to reduce the cost of telecommunications. So all types of hardware and software involved in acquiring, transmitting, and processing data are candidates for R&D."

A technical-institutional problem

Despite promising engineering solutions that may permit more-effective use of existing transmission capacity, researchers and industry experts agree that such approaches can never substitute fully for new transmission lines and facilities or generating capacity. The reality facing most utilities today, however, is that new transmission capacity and rights-of-way are extremely difficult, if not practically impossible, to site, license, and build on a time scale that has any meaning for planning purposes or for including the costs of such projects in rates.

"The issue of transmission system access and the ability to wheel power from one system to another addresses some of the most basic tenets of the electric utility business," comments Young. "The sanctity of the franchise area, the utilities' obligation to provide service to all who want it, ownership rights, and system security requirements are among the important fundamental questions. As customers and utilities reach beyond their local areas to purchase economy energy to an extent never anticipated in the original design of today's transmission system, the implications of the system's expanding role will most likely have a profound effect on the electric utility business.

"The institutional factors of price, priority, and availability currently appear more problematic than does technical deficiency," Young continues. "Any future legislative or regulatory actions in this area must also consider such a balance."

The challenges to the industry posed by the immediate and growing pressures for more wheeling and greater access to transmission facilities underscore the need for coordinated technical and institutional solutions to the problems of providing adequate, affordable, and reliable electricity supplies. ■

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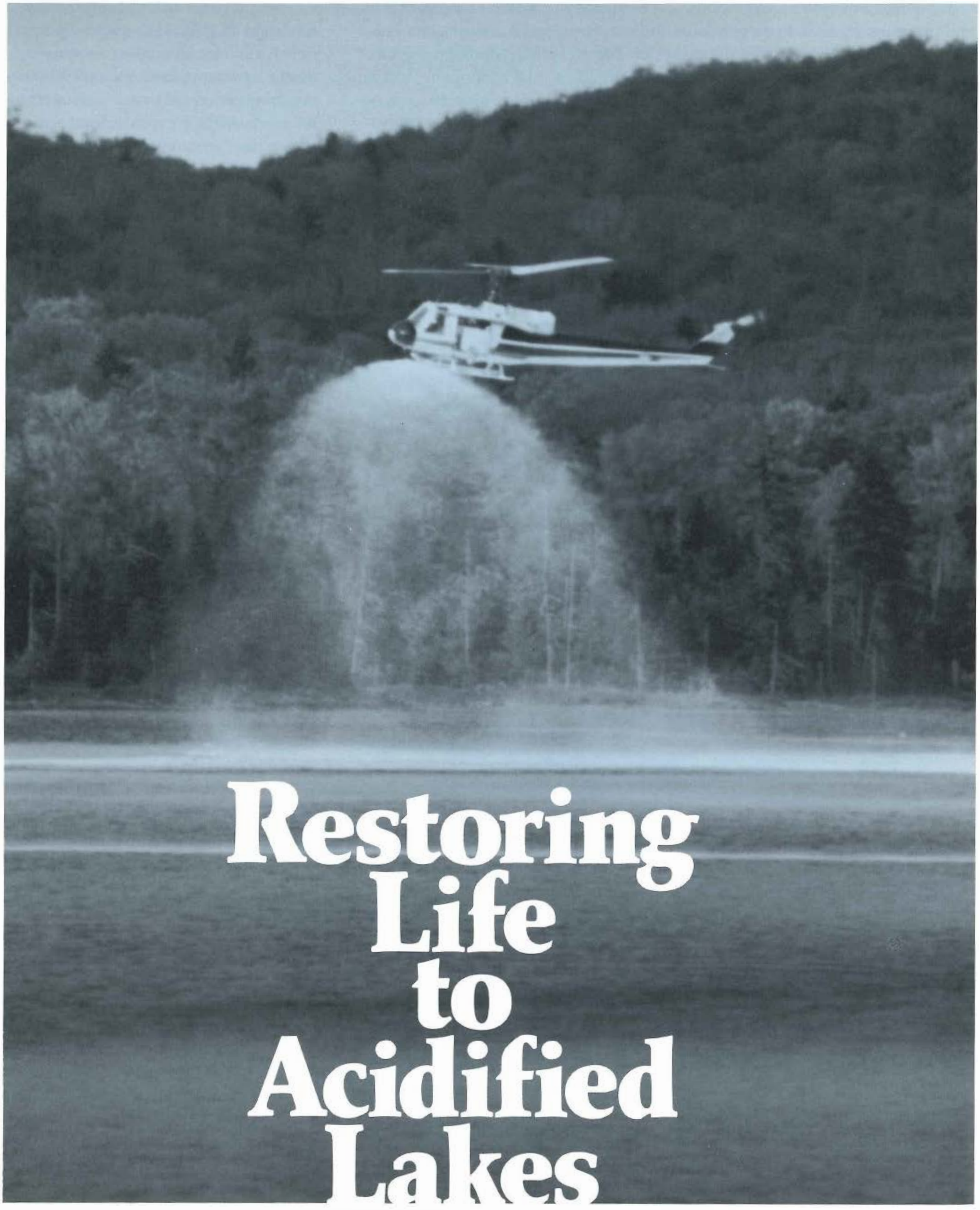
This article was written by Taylor Moore. Technical background information was provided by Narain Hingorani and Robert Iveson, Electrical Systems Division, and Frank Young, Planning and Evaluation Division.



Restoring Life to Acidified Lakes

International experience shows that liming of acidified lakes can restore healthy fish populations. New research into the long-term ecosystem effects of this technique confirms it to be a safe and cost-effective option.

A helicopter appears above the spruce-clad ridge and makes several low passes over the small Adirondack lake. A white spray fans out from a port in the aircraft's belly, painting broad stripes across the water. The finely ground limestone glistens on the surface for several minutes and then sinks slowly to the lake bottom, dissolving as it falls.

This lake has just been limed, a term used to describe the application of base materials to neutralize acidity in water and soils. Within several days, the lake will be stocked with brook and rainbow trout, two popular sport fish that once abounded here. If all goes as expected, fish will thrive in the lake for the first time in 15 years.

An established practice

Liming is not a new technique. The Romans used lime 2000 years ago to counteract the acidity of their soils, and American farmers apply 30 million tons of limestone each year for the same purpose. The first documented liming of aquatic systems occurred in the 1920s. By the 1940s liming was used in North American and Scandinavian fish hatcheries that were vulnerable to acidification from mine drainage and naturally acidic bog waters.

In the 1970s wet and dry acid deposition from airborne industrial emissions was identified as the likely cause of decline in the pH (rise in acidity) of some 18,000 lakes and 90,000 km (56,000 mi) of streams and rivers in Sweden. In response to the loss or reduction of fish populations in many of these waterways, the Swedish government initiated a liming program in 1976. With annual spending rising from $1 million in 1977 to $8.9 million in 1985, the Swedes have applied about 400,000 tons of limestone to 3000 lakes, 100 streams, and several entire watersheds. The ecological response to the Swedish liming has been positive, particularly in the reestablishment of healthy fish populations in many lakes. More-modest liming programs in Norway, Canada, and the United States have been similarly successful. About 100 U.S. lakes have been treated, mostly by state conservation agencies and private groups in the East.

A private organization called Living Lakes, Inc., was recently formed to provide technical assistance and financial support for the liming of acidified lakes and streams throughout the United States. The organization's $5 million annual budget is currently funded by 15 electric utilities and 5 coal companies. Robert Brocksen, executive director of the organization, explains, "The goal of Living Lakes is to demonstrate that liming is technically feasible as a method to mitigate surface water acidity." The group will focus initially on lakes in the Northeast and Middle Atlantic states and on the boundary water areas of Minnesota, Wisconsin, and Michigan. Later, it may expand its activities to vulnerable high-elevation lakes in the Sierra Nevada, Rocky Mountain, and Cascade ranges. "Regardless of the approach society takes in controlling the sources of acid deposition," says Brocksen, "liming can play an important role in restoring affected waters."

Although limestone ($CaCO_3$) is the most popular neutralizing agent, other materials like hydrated lime [$Ca(OH)_2$], ground seashells, fly ash, and soda ash have also been used. Liming materials can be applied from planes, boats, and land vehicles, spread on the ice of frozen lakes and streams, or held in porous containers through which stream water flows.

The dosage required varies with the neutralizing power of the agent and the flow rate and acidity of the water being treated. Small limestone particles dissolve faster and thus have greater neutralizing efficiency than large particles. Particles 0.25 mm (0.01 in) or smaller are five times as effective as particles greater than 2.4 mm (0.1 in). However, if limestone dissolves too fast while it is all in upper water layers, it can be flushed out of the lake more readily by storms before it penetrates and neutralizes deep waters. To ensure that the entire water column is neutralized and that some residual limestone sinks to the lake bottom, most liming programs use particles between 0.5 and 0.75 mm (0.02 and 0.03 in).

Whenever possible, liming dosages should be based on lake volume and typically range between 10 and 30 grams of limestone per cubic meter of lake water

EFFECTS OF LIMING ON LAKE ECOLOGY

Thousands of lakes in Scandinavia and more than 100 in America have been limed to neutralize acidity. Most operational liming programs have focused exclusively and successfully on creating conditions suitable for sport fish, but EPRI's lake acidification mitigation project (LAMP) is taking a broader and more-detailed look at liming's effects on entire lake ecosystems.

Testing the Waters Before Liming

1 Before liming two fishless lakes in New York State (Cranberry Pond and Woods Lake), researchers monitored water chemistry and populations of algae and zooplankton. Trout confined to mesh bags suspended in the lakes before liming died within several days, confirming that the lakes would not support fish.

(0.01–0.03 oz/ft^3). Because lake volume is often not known, however, some programs approximate the dose needed on the basis of surface area, applying about 2200 kg/ha (1960 lb/a).

The costs of liming vary with the type and amount of neutralizing agent used, the application method, and the remoteness of the site. Douglas Britt is president of International Science and Technology, Inc., a firm that has helped design and implement numerous liming programs for government and industry. "Liming costs can range widely," he explains, "and the methods used for lakes are distinct from those used for streams." Britt states that equipment for liming a single stream costs from \$10,000 to \$50,000 and that annual operating costs can range from \$8000 to \$100,000 for streams with flow rates up to 5 m^3/s (177 ft^3/s). "A 16-hectare (40-acre) lake representative of those treated in most liming programs will cost \$15,000 to \$45,000 to lime and maintain for 10 years," says Britt. (These figures include a second liming several years after the first treatment.) The lower end of the range includes lakes accessible enough to be treated by boat, whereas the more-expensive treatments are by helicopter at remote sites. At these prices, between 71,000 and 213,000 ha (175,000–526,000 a) of lake surface could be limed for the cost of one \$200 million sulfur dioxide scrubber on a coal-burning power plant. In comparison, the total surface area of all lakes in the Adirondack Ecological Preserve of upstate New York (exclusive of Lake Champlain) is about 93,000 ha (230,000 a).

Not a panacea

Liming cannot restore all acidified waters or overcome all water quality problems that kill fish and other aquatic organisms. Some lakes are too shallow, too low in dissolved oxygen, too high in organic matter, or too polluted with various toxins to support fish. Even where acidity is thought to be the primary problem, liming is not necessarily a cure. The New York State Department of Environmental

Conservation limed 19 naturally acidic bog ponds between 1959 and 1963 to determine whether neutralization would improve trout production. Although the treatments raised pH in all cases, low oxygen levels prevented suitable fish habitats from being created in some of the ponds.

In a liming program on acidic lakes contaminated with metals from North America's largest smelters in Sudbury, Ontario, researchers found that all the fish stocked in the lakes after liming died from residual metal toxicity despite the fact that pH in the lakes was raised to safe levels.

Water continually flows into and out of most lakes, and eventually all the water that was in the lake at a given time will be replaced by inflow from precipitation, runoff, surface inlets, springs, and groundwater. The frequency with which a lake exchanges an amount of water equal to its volume is called the flushing rate. This does not mean that all the water leaves the lake at once. Some water may remain in the lake for many years, and some may flow through in less than a month, but the flushing rate expresses an average rate of exchange.

Lake flushing is critical in determining the cost of lake liming. Generally, a single liming application will maintain acceptable conditions for up to three flushing periods because some limestone settles to the lake bottom and is not carried away by lake outflow, and some of the neutralized water will remain in the lake for several flushing periods.

The significance of flushing rates can be seen in the Adirondack region of New York State, which contains some 2800 lakes. According to Carl Schofield of Cornell University, many of the acidified lakes in the Adirondacks are small (<4 ha, <10 a), remote headwater lakes with high flushing rates that render them costly to lime.

For lakes with high flushing rates, several alternative liming techniques are more practical than repeated surface treatments from aircraft or boats. Fixed

Liming the Lakes

2 A slurry of finely ground limestone was loaded from a tanker truck into a helicopter, which applied 46 tons of slurry to the lakes. Lake pH jumped from less than 5.0 to 9.0 pH immediately after liming and then fell gradually in the following weeks. Caged fish suspended in the lakes during liming showed much higher survival rates than those in preliming cage trials.

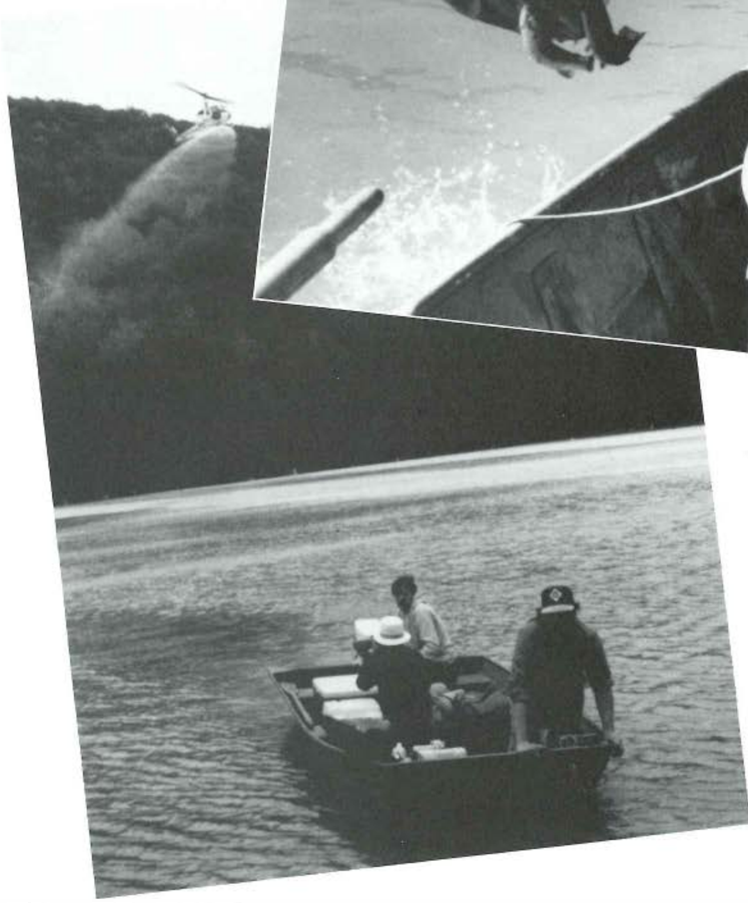
The Cost of Liming

Lakes[1]	\$1000–\$3000/ha (\$375–\$1125/a)
Streams[2]	
Equipment	\$10,000–\$50,000
Operation	\$8000–\$100,000/yr

[1] Costs for 10-yr treatment, with a second liming several years after the first.

[2] Streams with flows up to 5 m^3/s.

Source: Douglas Britt, Int'l Science and Technology, Inc.



Fish Release and Water Monitoring After Liming

3 Several days after liming, trout banded with identification tags were released into the lakes. They were free to swim throughout the lakes and to leave by outlet streams. Water sampling continued at regular intervals throughout this period. As expected, Cranberry Pond, with a more rapid rate of water exchange, was found to reacidify more rapidly than did Woods Lake.

limestone applicators can be placed in the lake or in its major inlet streams to provide continual small doses of neutralizing agent. Alternatively, all or part of the watershed soils can be limed. As precipitation falls on the ground around the lake it will absorb some of the limestone and be neutralized as it passes through the watershed.

EPRI takes a closer look

Although liming has been used for many years to restore sport fisheries in acidified waters, few studies have examined the long-term effects of this process on entire aquatic ecosystems. In 1982 EPRI cosponsored a conference with the U.S. Fish and Wildlife Service, the U.S. Department of Energy, and the American Petroleum Institute to determine if more research was needed to assess the broader impacts of liming on lake biology and chemistry. The answer was yes.

EPRI adopted many of the recommendations from the conference in initiating the lake acidification mitigation project (LAMP) in 1983. According to EPRI project manager Donald Porcella, "LAMP is more than a liming study. It is a comprehensive, integrated ecosystem experiment that should provide a wealth of insights into the behavior of aquatic systems under different conditions. Through the experiments now under way in LAMP, we will learn a great deal about the biologic and chemical processes involved in lake neutralization, as well as the changes that occur as lakes acidify."

The project is divided into two principal tasks. The first task is to gather and synthesize all existing relevant information on liming and its effects. LAMP's prime contractor, General Research Corp., worked with American, Canadian, Swedish, and Norwegian investigators to compile existing data on biologic and chemical responses to liming. This effort was completed in 1985, and a draft was published as an appendix to LAMP's second annual technical report.

The second main task under LAMP is

to develop a model for calculating optimal liming doses, to identify appropriate liming techniques, and to lime selected lakes, intensively monitoring their chemical and biologic status before, during, and after treatment. Porcella explains, "We are more interested in the ecological effects of liming than in the liming process itself. Because there is an established body of experience in the liming of lakes and much less experience with streams and watersheds, we decided to use well-known lake treatment techniques so we could focus on the system response."

LAMP researchers determined that the best way to answer some key questions about ecosystem responses was to lime lakes under three sets of conditions: reacidification, maintenance liming, and preventive maintenance liming. In the first case, a lake with a rapid flushing rate would be limed, stocked with fish, and then allowed to reacidify. The reacidification process and its effects on fish and other organisms would be closely monitored. In the second instance, an acidified lake with a moderate flushing rate would be limed, stocked, and relimed as necessary to maintain conditions that would permit the establishment of a self-reproducing fish population. At the third site, lime would be added and enhanced conditions maintained in an acidified lake with an existing, though stressed, fish population. Because of the number of known acidified lakes in the Adirondacks and the extensive baseline data on the region, three lakes from this area were selected for the LAMP study.

Cranberry Pond, a small (7 ha, 17 a), shallow body with a pH consistently below 5.0, was chosen for the reacidification study. Because of its high flushing rate (four times a year), Cranberry Pond was expected to reacidify in less than one year after treatment, giving researchers an opportunity to evaluate their dose and reacidification models. Woods Lake, a larger body (23 ha, 57 a), was selected for maintenance liming and stocking because it has chemical and biologic

Fish Survival After Liming

4 Researchers used fish traps on the outlet streams and netting in the lakes to assess fish survival and migration. More than half of the fish were alive five months after liming. Captured fish were measured, inspected, and returned to the lakes. Monitoring is continuing in order to study the reacidification process in Cranberry Pond, as well as to see if fish successfully reproduce in Woods Lake, which will be limed again this year.

characteristics similar to those of Cranberry Pond and because its moderately slow flushing (about one and one-half times a year) would allow neutral conditions to be maintained without frequent liming. Woods Lake also offered the benefit of extensive baseline data from earlier EPRI lake acidification studies in that watershed.

The largest LAMP study site, 63-ha (156-a) Little Simon Pond, supports an acid-stressed fish community in waters that typically range in pH between 5.0 and 5.5. With the slowest flushing rate of the three lakes (once every 15 months), Little Simon Pond was chosen for the preventive maintenance study.

Gathering baseline data

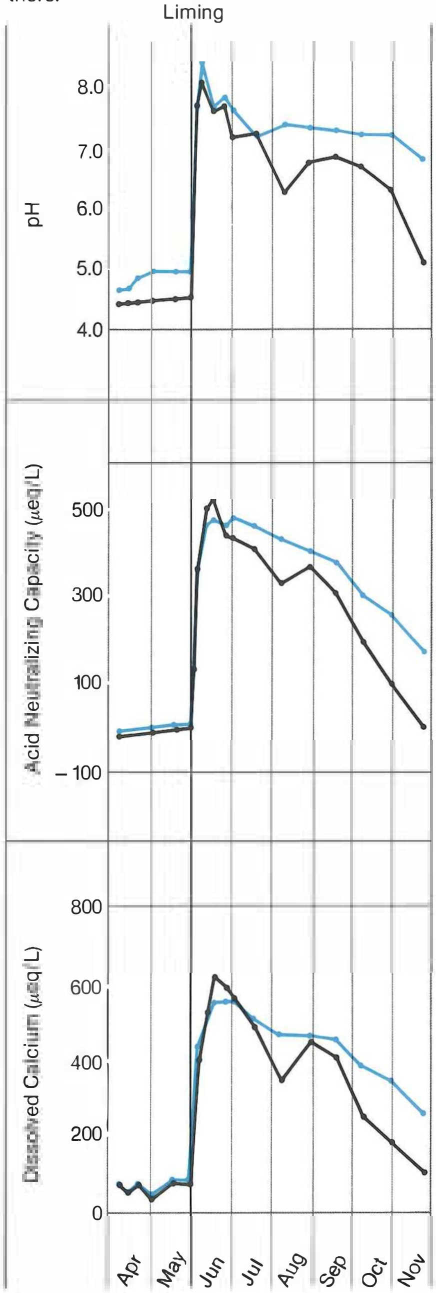
Baseline monitoring at Cranberry Pond and Woods Lake began in January 1984 and at Little Simon Pond in the autumn of that year. Researchers wanted a complete inventory of conditions in the lakes before liming began. Most of these measurements were repeated during and after liming. They chronicled hydrology, water and sediment chemistry, populations and species distribution of fish, zooplankton, algae, macroinvertebrates (e.g., crayfish), and rates of organic matter decomposition.

Chemical analyses were performed for some two dozen parameters, including dissolved oxygen, pH, calcium, aluminum, acid-neutralizing capacity, nitrate, sulfate, ammonium, chlorine, and phosphorus. Aluminum is of particular concern as the prime culprit in the death of fish in acidic waters. In pure rainwater (near pH 5.5) aluminum appears principally in nontoxic, insoluble forms, but in more-acidic conditions it forms soluble compounds that can weaken or kill fish by damaging their gill tissues.

One theory holds that acid rain leaches naturally occurring aluminum from watershed soils. The toxic, soluble aluminum then flows with the runoff and groundwater into streams and lakes. This theory is supported by measurements showing that acidified lakes frequently contain elevated levels of toxic aluminum compounds. LAMP researchers want to learn more about how liming changes the forms of aluminum in lake waters and the biologic effects of these chemical changes.

Water Chemistry Monitoring

Woods Lake (color) and Cranberry Pond were monitored before, during, and after liming for more than a dozen water chemistry parameters. Changes in pH, acid-neutralizing capacity, and calcium (measured at the lake outlets) are three primary indicators of conditions important for fish life. Because of its higher flushing rate, Cranberry Pond is returning to its preliming condition more rapidly than is Woods Lake, which offers scientists a rare opportunity to study the reacidification process. The slower flushing rate of Woods Lake has kept its condition more stable since liming. Researchers believe this stability may allow a self-reproducing trout population to become established there.



Another chemical of special interest is phosphorus, an important nutrient that is often in short supply in aquatic systems. Some studies have shown phosphorus concentrations falling after liming, while other studies have shown just the opposite. Because the overall productivity of many lakes depends critically on phosphorus availability, LAMP investigators want to better understand how liming affects this key parameter in the long term.

Studying the effects on fish

Fish experiments were conducted in three stages at Woods Lake and Cranberry Pond: before, during, and after liming. Brook trout fingerlings under 3 in (76 mm) in length and yearlings up to 7 in (178 mm) were placed in cages suspended in both lakes several times during a six-month period before liming began. The purpose of these tests was to determine the rate of fish survival in the acidified waters before they were neutralized. According to Schofield, who is a principal investigator in LAMP, only 6% of the fingerlings and 12% of the yearlings survived the cage trials. These findings clearly indicate that the lakes were not in suitable condition to support brook trout.

On May 30 and 31, 1985, a helicopter applied 46 tons of limestone slurry to Woods Lake and Cranberry Pond. (Little Simon Pond will be limed in spring 1986.) Guided by grid layouts marked in advance, the pilot deposited uniform amounts of slurry (about 29 g/m^3, 0.03 oz/ft^3) on both lakes.

More caged fish were placed in the lakes immediately prior to liming. The fish were monitored during liming and for several days afterward to document the immediate effects of lake neutralization. Their survival rate was far higher than had been the case with cage trials before liming and was the same as in neutral reference lakes and in tests performed several months later in the limed lakes.

Several days after liming, both lakes were stocked with fingerlings and yearlings that were free to swim anywhere in the lakes or to migrate out of the study sites by way of outlet streams equipped with fish-counting traps. Fish survival in Woods Lake and Cranberry Pond, neither of which could support fish before liming, rose dramatically after liming. Surveys conducted in late October 1985 showed that 50–60% of the stocked fish had survived. By November, however, the rapidly flushed Cranberry Pond was reacidifying. Two-thirds of the fish counted in the October survey responded to falling pH by migrating out of the pond through an outlet stream where they were trapped. Some of these fish were returned to Cranberry Pond; very few survived to migrate a second time.

As Cranberry Pond continues to reacidify, investigators will obtain a rare, detailed picture of the changes in water chemistry and biology that occur as pH falls over time. They will be watching carefully to learn if there are critical thresholds in various parameters, which, when they are crossed, have dramatic effects on aquatic organisms. The identification of such thresholds will help fine-tune future liming programs.

Another important question that the LAMP research will help answer concerns the prospects of mitigating the effects of acidic pulses that occur during spring snowmelt and during heavy rainfall periods. The prevailing explanation for the elevated acidity of runoff at these times is that watershed soils, which partially neutralize groundwater during most of the year, are waterlogged during the spring. Consequently, much of the snowmelt or rain runs along the surface or through the shallow subsurface soil horizons and receives very little buffering before reaching surface waters. Even if conditions through the rest of the year are ideal for lake productivity and fish growth, a brief acid pulse may damage ecosystem functions. If this occurs at critical periods in reproductive cycles, it might prevent fish populations from being self-sustaining, even though stocked fish may survive in the lake year-round.

Because researchers hope to establish conditions that will support self-reproducing trout populations in Woods Lake, they constructed artificial spawning sites in the lake, pumping water from an inlet tributary up through calcareous gravel beds. The pumped water simulates the groundwater upwellings brook trout like to lay their eggs in, and the calcareous gravel neutralizes the water in the vicinity of the spawning beds. The stocked trout used the spawning beds extensively in 1985. Researchers will be watching closely in the spring of 1986 to monitor the survival of newly hatched fry that will emerge when the snowmelt is under way.

Little short-term change in phosphorus levels was detected following liming. "Moreover," comments Porcella, "algae, zooplankton, and other intermediate organisms in the aquatic system are responding in ways that would be expected with the introduction of fish and limestone. Species composition has varied in response to higher nutrient levels and changing pH, but liming appears to cause no long-term effects on aquatic communities."

Charles Driscoll of Syracuse University is responsible for the water chemistry portion of LAMP. According to Driscoll, "The most interesting result thus far has been the response of aluminum to changing pH. Within hours after liming, the pH of both lakes rose from about 5.0 to around 9.0, and concentrations of soluble aluminum rose as well." Aluminum is least soluble at around pH 6.0 and will dissolve more readily at both higher and lower pH levels. It appears, however, that the forms of soluble aluminum that appear at high pH (different from the soluble aluminum compounds that form at low pH) are not measurably toxic to fish, because the caged trout placed in the lake during liming exhibited no signs of harm. "Over the course of several weeks the lakes fell back to pH 7," continues Driscoll, "and as this happened, aluminum precipitated into nontoxic, insoluble forms."

The results of monitoring the water chemistry in the lakes will also be used to validate the dose and reacidification models developed early in LAMP and the integrated lake-watershed acidification model (ILWAS) that was developed in an earlier EPRI study. Porcella says, "We are calibrating these models against measured results in the field to ensure that they can be used with confidence to calculate liming doses and rates of reacidification."

A clearer picture emerging

The LAMP findings are already providing valuable insights into the subtle processes that occur as lake acidity changes. Because LAMP is digging deeper into the details of ecosystem responses than did earlier studies, it will offer a more comprehensive picture of the long-term response of aquatic systems to liming and to reacidification. As Porcella puts it, "We hope to emerge from LAMP with a much broader understanding of the long-term ecosystem effects of liming and with predictive models that can help liming programs to be as effective as possible. Liming cannot solve all our water quality problems, but it is a powerful tool that, when properly applied, can contribute positively to the restoration of acidified aquatic ecosystems." ■

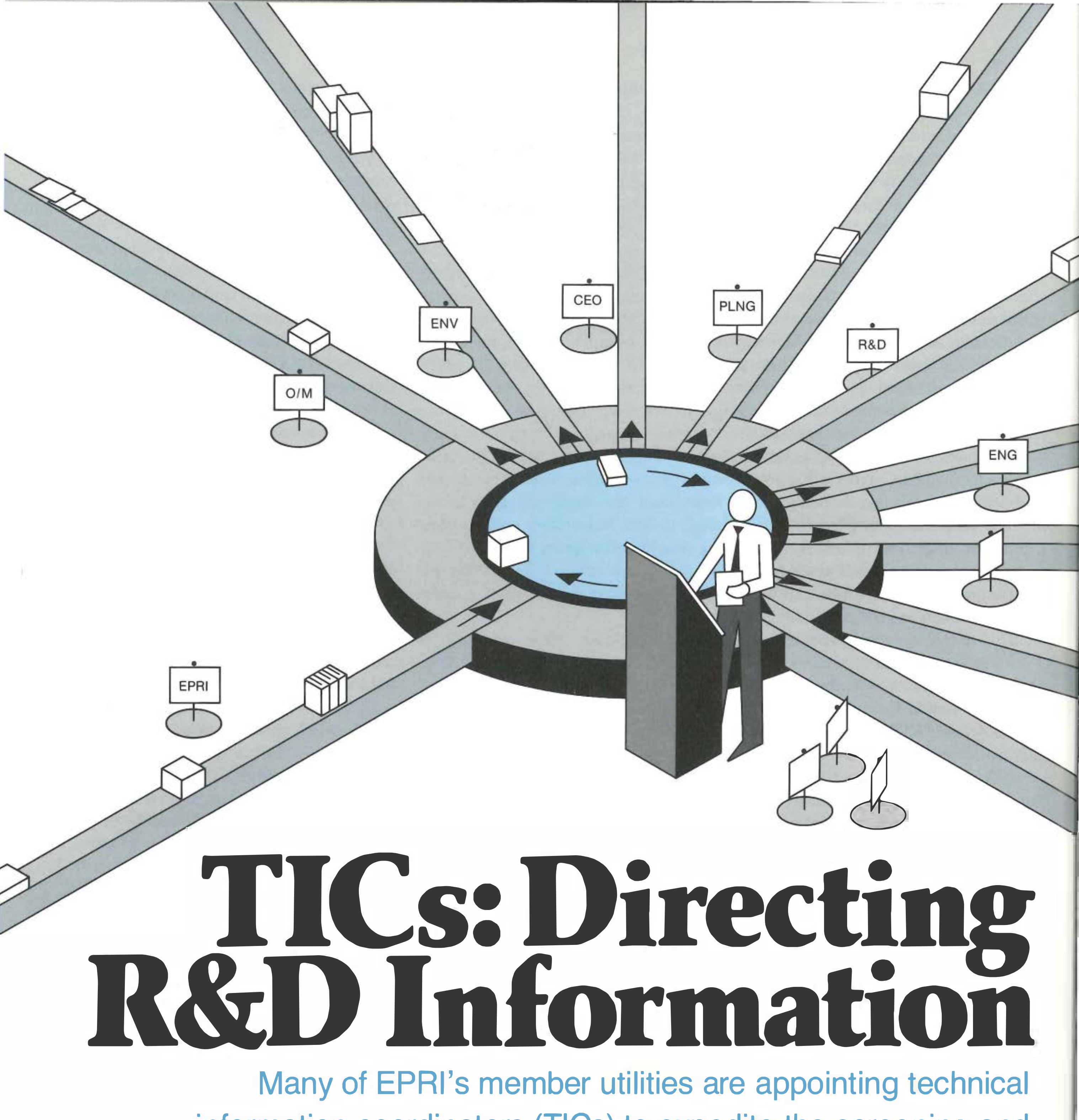
Further reading

Fisheries, Vol. 9, No. 1 (Jan–Feb 1984). Special issue on mitigation techniques for acidified surface waters.

U.S. Fish and Wildlife Service. *Liming of Acidified Waters: A Review of Methods and Effects on Aquatic Ecosystems*. Prepared by General Research Corp., December 1982. FWS/OBS-80/40.13.

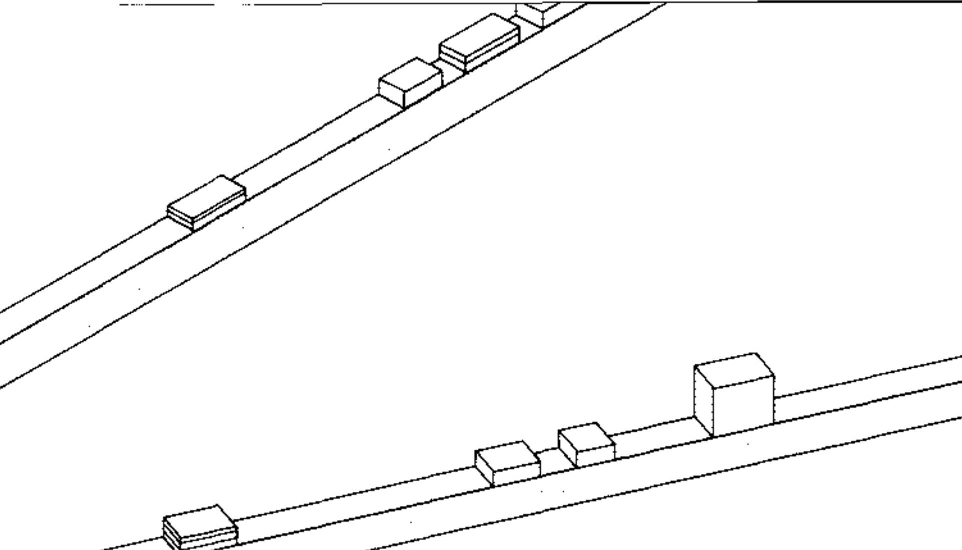
Feasibility Study to Utilize Liming as a Technique to Mitigate Surface Water Acidification. Interim report for RP1109-14, prepared by General Research Corp., April 1982. EPRI EA-2362.

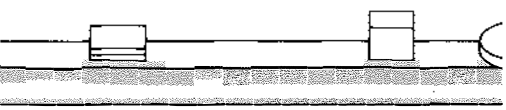
This article was written by Michael Shepard. Technical background information was provided by Donald Porcella, Energy Analysis and Environment Division.



TICs: Directing R&D Information

Many of EPRI's member utilities are appointing technical information coordinators (TICs) to expedite the screening and dissemination of EPRI's research output and to help assess its value in use. The basic TIC function is to build an information distribution system within the utility.





Technical information coordinators (TICs) are pretty much a new idea in the electric utility business. As either a title or a description, the words are a sign of the times—our information age with its rapidly expanding universe of technology resources.

In practice, TICs are official communication links between EPRI and its member utilities. They are utility staff members charged with the process steps of technology transfer—the systematic traffic and documentation involved in obtaining, evaluating, and applying the products of electric power R&D and then assessing the results.

"A TIC tries to get all the R&D products from EPRI that have possible application in his or her utility," says Francis Carney of New York State Electric & Gas Corp. (NYSEG). "Also," he quickly adds, "the TIC should somehow be able to focus his utility's attention on those products."

Carney knows from experience. He has been a TIC for six years, almost since he moved from the generation department into research at NYSEG. He is the utility's R&D vice president today, and this helps put him among what he calls the lucky TICs. "It's a matter of being given the time to do the job. I'm not sure it takes 40 hours; probably not. Something like 20, I'd guess, plus a little support by executive management."

Distinguishing lucky and unlucky TICs is easy, according to Carney. "The unlucky ones are busy 40 hours a week with other tasks and their need for TIC time isn't much recognized. Along the same line—how should I say it?—some of them don't have corporate clout."

Carney's intense interest in what makes TICs tick goes beyond his work at NYSEG. He was named chairman of EPRI's TIC Committee when it was formed in 1983, served two years in the position, and continues as a member of that advisory group. From his varied experience, Carney knows that EPRI members see the technical liaison function in a variety of ways, placing it at different levels in different departments and according it a great range of responsibility and authority.

Guidelines for TIC success

There is no typical TIC, just as there is no typical utility. Circumstances of size, region, function, ownership, and the like continue to motivate the appointment of librarians, junior engineers, planners, administrators, research managers, and engineering vice presidents as TICs. Even general managers or presidents may take on the responsibility in small utilities. More and more often, however, in an effort to ensure a breadth of technical understanding, as well as organizational familiarity, utilities are designating experienced individuals from middle-level engineering management.

TICs are sharply aware of the different audiences with which they work, as well as the variety of their own skills. Richard Locke illustrates that variety. Locke is an R&D contract administrator at Southern Company Services, Inc., and he succeeded a vice president as TIC for his company. During the past year, he chaired a subcommittee of the TIC Committee charged with developing guidelines for TIC function.

Now in the process of final approval and slated to become a part of every TIC's *General Reference Document,* the guidelines list desirable background and training, duties and responsibilities, and many tips and tools for carrying out the TIC job. But the emphasis is on three factors that especially define a TIC's effectiveness as "a central resource to utility employees for special information problems or matters concerning EPRI." The three factors are visibility, management support, and department coordination.

As described by the TIC subcommittee, visibility has to do with wide recognition of the information coordinating function itself. Many of the specific tips in the guidelines describe how TICs can gain and hold that visibility in their own organizations by using such means as library services; regular internal communications about available EPRI products; announcements of R&D decisions and actions; displays, exhibits, and showings of print and video materials; conduct of informational briefings and workshops; and liaison with staff members who are industry advisers to EPRI.

Locke's subcommittee emphasized the importance of getting support from the top. Endorsement there helps establish the right climate to begin with; it also establishes a regular channel through which the TIC can report and build a record of technology transfer activities and results. Carney's sharply drawn image of lucky and unlucky TICs is a reminder of how day-to-day TIC authority is underscored by management attention or undercut by neglect.

"If a TIC is lucky, his or her chairman gets up at a company meeting, shakes a finger at all the VPs and department heads, and says, 'This is Jones, our TIC. When he brings something to your attention, you'd better listen. When he asks you to evaluate something, you'd better do it, or I'll be disappointed.' That's the easy way for it to happen," Carney says with a smile. Then he turns serious. "The other way is to try to talk people into giving you their time even though they don't have to."

Department coordinators are an invaluable adjunct of utility TIC function. They become a network for disseminating and collecting R&D information, especially in larger organizations and especially if they include the technical professionals who serve on the committees and task forces of EPRI's industry advisory structure. As the third point of TIC effectiveness, networking through department coordinators is highly structured. Locke's TIC subcommittee recommended creating an organizational overlay as extensive as the utility itself—individuals who are close to potential R&D users and can help target information and elicit responses.

The personal touch

In addition to knowing where the information should be routed within the utility, TICs also need to be or to become very familiar with EPRI's programs, products, procedures, advisory resources, information materials, distribution channels, and (especially) people. Some of this falls out of a TIC's work in trafficking inquiries between the utility and EPRI. Some comes from reading the *General Reference Document*, and some comes from acquaintance with EPRI's member services representatives. TIC workshops and visits to EPRI serve to attach faces to research projects, thus clarifying and expediting information flow.

A TIC's personal communication skills bring it all together—visibility, support, networking, utility background, and EPRI orientation—so that he or she is an effective, sensitive instrument of information flow. There is a good deal of practical psychology involved if normal barriers to innovation and change (such as inertia and "not invented here") are not to obstruct the channel.

What, in fact, is the response to these often-subtle hindrances? In great measure it is a matter of accommodating interests and biases, making a genuine effort to take account of underlying questions and concerns. Involving people through interviews and surveys is useful; sometimes a former nay-sayer comes to feel vested in a matter under consideration, even to the extent of feeling responsible for its advent.

For every communication obstacle that shows up in a utility, however, there is an urgent request for R&D information. A TIC is seen as a central resource person, and a good TIC is one, not necessarily knowing the answer but knowing how to find it. Questions come from both directions; EPRI often needs input for its R&D planning, a project cosponsor, or a utility host for pilot- or demonstration-scale development. In fact, inquiries about EPRI research sometimes go from utility to utility without contact through EPRI at all, exploiting a collegial network of TICs that is proving to be an excellent resource.

Stemming a flood

From the beginning, EPRI encouraged the appointment of utility coordinators (the term first used) to help shape what were still new and unexplored relationships, as well as to be channels for information flow. And in the view of those coordinators and their colleagues, EPRI's volume of R&D reports was a problem from the start.

For most of EPRI's research managers, individual projects were completed at a frustratingly slow pace. But for utility men and women, primarily engaged by their daily problems of system planning, engineering, and operations, EPRI's total R&D output soon became a rising tide. Indeed, an individual's first perception was usually that of a flash flood.

That was the experience of Robert Butz, today's TIC Committee chairman. Having worked for New Jersey's Public Service Electric & Gas Co. since 1958 and as its R&D department administrator since 1970, Butz is an old hand in the business of R&D information, going back well before EPRI was established, "when there wasn't any single institution dedicated to utility R&D and no continuous stream of reports demanding to be managed—that is, screened for immediate use or neatly pigeonholed for future access."

But the situation changed in the 1970s because PSE&G's own R&D was expanding simultaneously with EPRI's early growth. Butz became the utility's corporate information coordinator in 1979, his appointment motivated, as he tells it, by a snowstorm of EPRI reports and his management's not altogether rhetorical question, "What'll we do with these?" Butz volunteered to take responsibility for the utility's R&D information flow. Somewhat less intentionally, he thereby became one of EPRI's member utility coordinators.

"At the outset," Butz says, "it was like being a funnel—everything went through me." Eventually, however, as EPRI focused on information management in technology transfer, Butz came to see his role as that of a catalyst. By 1982 known as a TIC, Butz established an informal network of 17 sub-TICs, anticipating the TIC Committee's recommendation for department coordinators.

Under the guidance of these sub-TICs, R&D information is systematically reviewed and categorized in PSE&G's departments. An important part of their work is ensuring that other staff members submit profiles of their technical interests to EPRI. By doing this they become regular recipients of the one-page summaries that EPRI now publishes for all project reports and mails to self-selected utility audiences.

Organizing the TICs

The technical interest profile (TIP) system arose both in utility practice and in EPRI's own work to limit and channel its flood of paper. But it developed by degrees. By 1981, for example, member utilities were no longer automatically receiving one copy of everything. EPRI project managers were writing overviews only a few pages long, and these were being distributed instead of complete research reports, which could then be ordered.

Utility recipients were being asked to categorize their interests, but the matrix had been drawn along EPRI's organizational lines, and the resulting subject areas were often criticized as being too broad. It was still difficult for utilities to get their arms around EPRI, much less to assimilate its output.

The year 1981, therefore, was also when EPRI's Industry Relations and Information Services (IRIS) group began a concerted effort to slice the Institute's output into still more digestible pieces, target utility audiences more specifically, make the Institute's people more visible and accessible, and organize and transmit information in new ways—all and all, as someone says now, "to be more user-friendly."

So these achievements would be truly useful, another objective was to help member utilities update their perception of the utility coordinator's role in technology transfer.

These were not tasks for EPRI to do unaided. If they were to be done correctly, and if the results were to be accepted wholeheartedly, there had to be member utility input, just as in EPRI's technical advisory structure. Thus began a series of exploratory workshops involving various IRIS staff members with a number of longtime utility coordinators, Carney and Butz among them.

An important outcome was the TIC Committee, called into being late in 1983 by Vice President Richard Rudman as a source of guidance for the divisions of the IRIS group. Rudman's reasoning is straightforward. "We have to know how we're doing on information transfer—what's working, what isn't, what needs to be improved. Also, the committee is a source of new ideas that can help our performance." Accordingly, committee membership is broad, consisting of 18 TICs (each serving staggered three-year terms) who are selected to obtain a representative range of utility viewpoints.

Like other EPRI advisory bodies, the TIC Committee for the most part works jointly with EPRI personnel. Rudman is one, as are several of the IRIS staff who have frequent and responsible contact with utilities. These include Burton Nelson, EPRI's director of Regulatory Relations, who serves as committee secretary; Thomas Crawford, director of the Technical Information Division; Wayne Seden, manager of Research Applications in the Member Relations Division; and John Neal, manager of Member Services, also in the Member Relations Division.

TICs exchange information and know-how with each other at annual technology transfer workshops organized by EPRI's Member Services Department. Each regional gathering attracts from 20 to 50 TICs (plus other utility staff members) to hear from information specialists and R&D managers.

Expediting the information flow

EPRI's relationship with its members today is much more robust than at its beginning, when a few visionary and receptive minds in utility R&D or corporate management may have been EPRI's only connection with some utilities. Today, virtually all operating departments of a utility are logical places for EPRI connections. Neal speaks of an R&D pipeline that is full, "about 450 finished research products that we have documented and want to make sure members are aware of."

What's more, reports of completed research are being issued at the rate of 700 annually. Neal and his Member Services representatives see themselves as "helping utilities take advantage of the flow of information and to match it up with their own needs." But they are only 10 people and they have nearly 600 clients—counting the subsidiaries and service affiliates of EPRI's member utilities. The members have to help themselves. Clearly, this is where the TICs come in.

The basic premise is that the system for distributing R&D information be governed by utility demand as much as possible—delivering what utilities want, not what EPRI independently deems important. A corollary idea, coming to be realized in daily TIC practice, is that individual R&D topics are not as important as the information process itself.

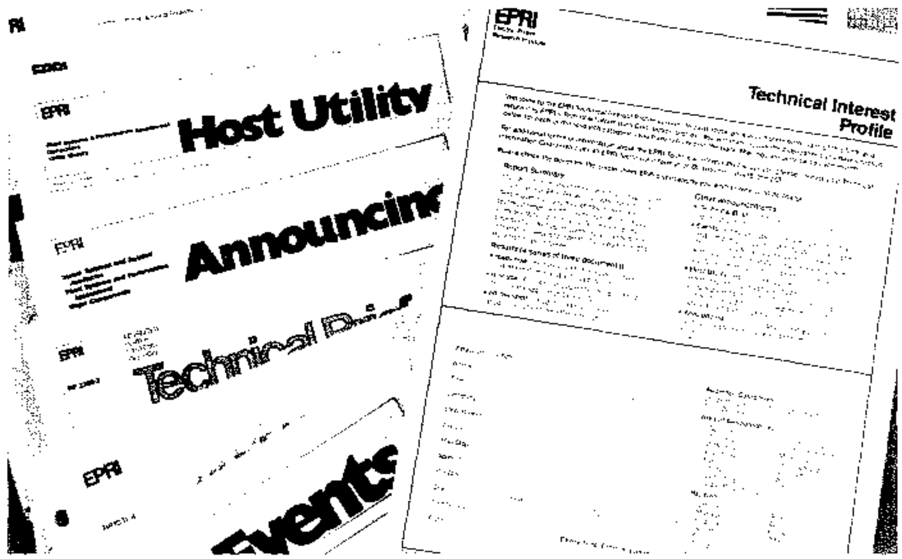
Two major aids to communication and technology transfer have evolved: the Technology Information Center and the TIP system. The center is a telephone hotline, a single number (415-855-2411) staffed by information specialists with the data bases and cross-references needed to answer questions about EPRI projects, contractors, and publications, or to refer callers to the right members of the technical staff.

The TIP system involves detailed survey forms, called technical interest profiles, to govern selection of the EPRI materials that are routinely sent to individuals at member utilities. Recipients can put themselves in line for R&D results and other information in any or several technical program areas. This fine-tuning has eliminated extraneous material, cutting the confusion it generates and thereby improving each individual's reception of needed information.

EPRI's distillation of reports to one-page summaries (for initial circulation) has also helped. The accurately delineated TIP data base is proving useful for distributing other information, too, such as the results series on first use, commercialization, and routine availability of R&D products; and announcements of workshops, needs for R&D host utilities, or the availability of computer software.

How information is packaged clearly influences a TIC's success. It is not simply a matter of being brief and direct, although this helps. It is also variety—appeal to different audience levels, appearance in different media, and availability through different channels.

Demand-driven technology transfer hinges on Technical Information Profiles, submitted by individuals to specify the R&D topics to be called to their attention by one-page report summaries and other special announcements. EPRI member personnel receive profile forms from their TICs; others call EPRI's Technical Information Center at (415) 855-2411.



For example, engineers predominate in EPRI's utility audience. Technologists rather than scientists, they are concerned with immediate needs, solutions available for use today. They demand that R&D information be orderly and selective so that practical and applicable results are easy to identify.

Utility management can also be quick to act on R&D results that have immediate applicability and (especially) near-term economic value. Not only is this good business but it documents the return on R&D dollars invested with EPRI, a plus in a utility's regulatory relationship and in its own consideration of a larger R&D budget allocation.

Assessing R&D benefits

Although TICs are often occupied mainly with obtaining and distributing R&D information, economic evaluations of new technologies are becoming a recurrent requirement. There is a frequently voiced need for a straightforward, consistent, defensible, and quick way to assess a utility's application of R&D results from EPRI. This topic was taken up in 1984 by a TIC subcommittee. NYSEG's Carney now chairs the cost-benefit analysis group, but much of its work was done last year under Geraldine Miller of Arizona Public Service Co.

Miller is a research scientist who has been her company's TIC for four years. Coordinating the distribution and evaluation of EPRI information takes one-third of her time; her other work includes management of several large data bases and a small technical reference library.

Miller is emphatic about the need for the cost-benefit analysis subcommittee's work. "Most of us must justify EPRI membership contributions to our managements and sometimes to our regulatory commissions. This means assessing the benefit expected from a new technology as part of the decision process before it's used or the benefit actually realized after it's in place." Such systematic comparison of an R&D investment and its payoff is a far cry from the practice of R&D as a purely exploratory search undertaken on faith. Perhaps in part because a pooled R&D program does not exactly match any utility's own choice, EPRI members are continually motivated to check their individual cost-benefit ratios.

Miller is equally emphatic that utilities and their TICs seek an analytic approach that can be useful to any of them. Experience says it must be clearly defined. As one TIC remarked, "It's hard to get some engineers to assign a benefit value solely to some one product. They're scrupulous. They see many interacting factors, or they may conclude that some other new option of unknown economic impact would have appeared if the one under evaluation hadn't been adopted. They're reluctant to acknowledge that any single factor, by itself, can be credited with a stated saving."

Success for the subcommittee is taking shape as a utility cost-benefit model (UCBM), a menu-driven program packaged as a floppy disk for a microcomputer. "Anyone who is familiar with the methodology of revenue requirements analysis should be able to use it," says Miller. "Ease of use and consistency are its main attributes," she adds, "but lightning speed isn't really needed, because most of a user's time is spent compiling inputs." Miller underscores how much simpler it is to use the model to handle the time value of money (discounting estimates of alternative future costs and savings to their present value) so as to make consistent comparisons.

Reviewing R&D communications

Like the shared R&D venture that EPRI itself represents, the task of a TIC is being learned as it is practiced. Utilities are learning to systematize their reception, management, and use of a fast-flowing, ever-widening stream of technical information. EPRI, the large and dedicated source of that information, is learning to direct it more effectively. The task will become easier for both parties as it becomes more familiar, but it will never become any smaller.

TICs, separately and through their representatives on the TIC Committee, are showing themselves to be eager and inquisitive. Occasionally they champion individual R&D results for application in their organizations; most of the time they champion the orderly review and screening of many more R&D results.

For many individuals in EPRI and its member utilities, there is a constant tension about the appearance or the fact of selling new technology. It is not too many years since the chairman of EPRI's Research Advisory Committee probably spoke for most members when he said, "I don't think there is much that EPRI itself can or should do beyond working with utility coordinators and helping them disseminate results. . . . It's like putting a book into a man's hands. We can provide the information, but we can't read it for him."

EPRI must continue to respect utility opinion on this matter, but if Butz and Carney are any indication, sentiment is changing. In their view, the leading TICs are those who take on the selling role, selling their own utilities on the need for R&D, a proactive role toward EPRI, and a thorough evaluation of as many new technologies and methods as possible. Butz says it flatly. "Selling the value and support of R&D is the most important thing TICs can do."

This evaluation sparks no argument from EPRI. "They're an invaluable sales force for the R&D function," observes one individual in EPRI's IRIS group. "Sometimes, though," he adds with a smile, "they seem to want to run the operation!"

That afterthought has nothing to do with R&D substance or management, but it does acknowledge a sharp TIC concern for the nature and distribution of R&D information. The subject is close to all TICs' hearts: aside from their own talents, communications materials mean the most to their effectiveness. Last year, for example, several TIC Committee members reviewed a 1984 report on EPRI's print, film, and tape publications. Detailed editorial and graphic criticism were not the point, according to Butz, but he noted that TICs can offer helpful judgments of whether a publication authentically addresses its intended utility audience.

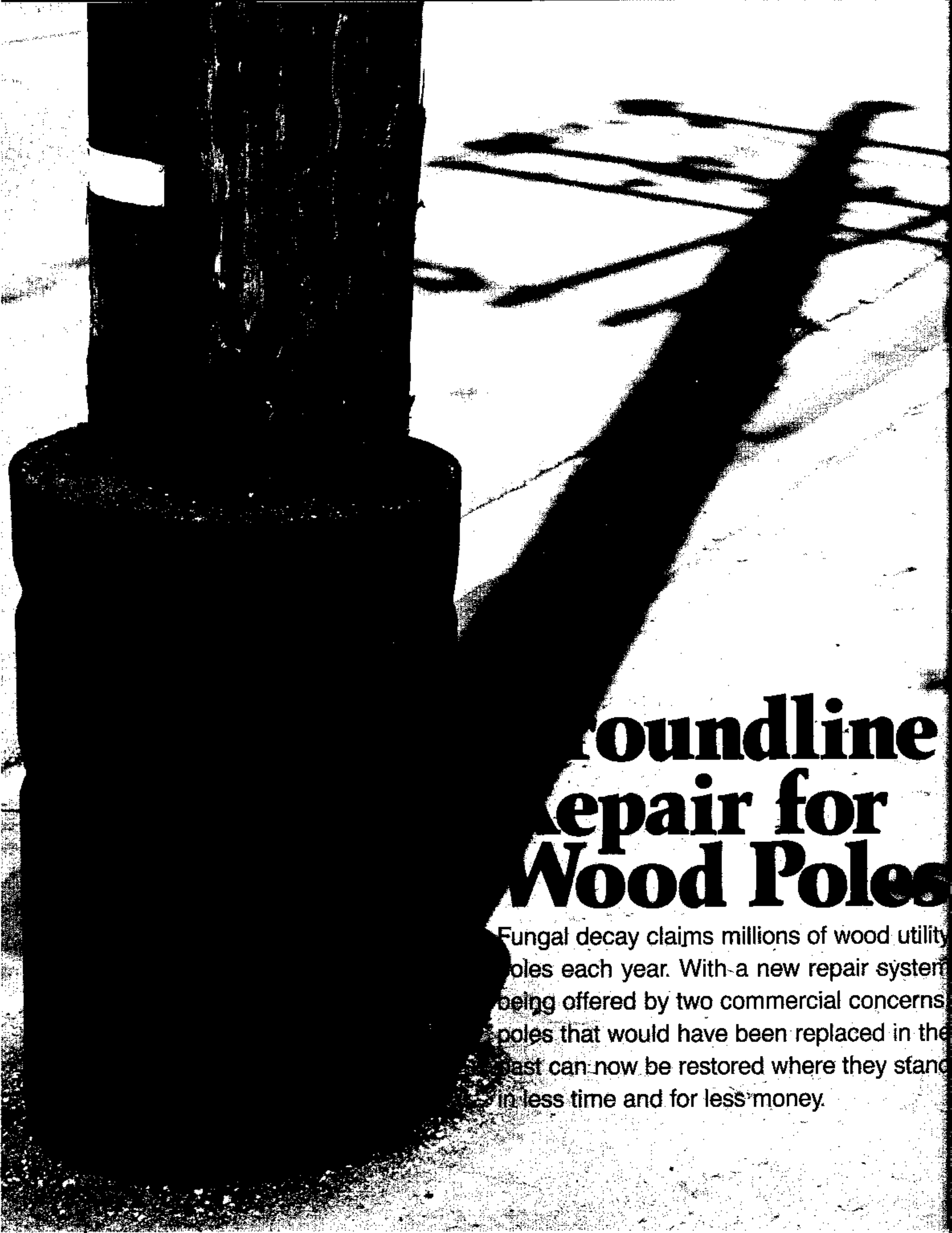
Butz and Carney echo each other's words again, this time on the role of TICs as advisers to EPRI. Butz comments, "Users—the utilities—need to be heard on how EPRI disseminates results, the extent of the information, and the form it takes." And Carney observes, "This is a subject on which I think the TIC Committee has sort of overwhelmed EPRI's staff people once or twice. I sense they've tried to slow us down. There are probably reasons for it," he acknowledges. "It's true that many utility people have to be intermittent in their advisory roles. But this is different. A lot of TICs are saying, 'Please use us more!' "

By such growing interest and activity today, individually at their own utilities and banded together in their EPRI advisory role, TICs are successfully challenging what Neal calls the three illusions of technology transfer. First, for example, technology transfer until recently was seen to be an automatic function; the value of R&D would be self-evident, a sort of magnetic appeal to utilities. The fact is that technology transfer is a very intentional process that must be designed and orchestrated—indeed, sold.

Second, technology transfer was once limited to hardware; nothing else was really technology. In practice, EPRI's work has probably yielded as many separate items of computer software, equipment guidelines, process specifications, and procedural manuals as it has separate components, machines, or systems.

Third, technology transfer formerly was treated as a sporadic phenomenon, at best an after-the-fact compilation of independent events or cases. The reality, as seen by TICs who increasingly feel pushed in their parttime assignments, is that technology transfer is an ongoing, structured practice, and so is the information management process by which TICs make it happen.

This article was written by Ralph Whitaker, feature editor. Background information was provided by Robert Butz, Francis Carney, Richard Locke, and Geraldine Miller, utility technical information coordinators; Olga Compton, Technical Information Division; John Neal, Member Relations Division; and Burton Nelson, Regulatory Relations Department.



Groundline Repair for Wood Poles

Fungal decay claims millions of wood utility poles each year. With a new repair system being offered by two commercial concerns, poles that would have been replaced in the past can now be restored where they stand in less time and for less money.

From the end of World War II through much of the early 1960s, America enjoyed an unprecedented building boom. One important aspect of this boom was the greatly expanded use of electricity, reflected by a vast number of new wood utility poles erected during the period. Unfortunately, many of these poles have deteriorated faster than expected, largely because of groundline damage caused by fungal decay. An estimated 20 million wood transmission and distribution poles now have to be replaced—at a cost of billions of dollars a year—unless their integrity and useful life can be increased significantly.

EPRI has recently developed and patented a repair method that can both restore the original groundline strength of a wood pole and greatly retard further deterioration. The method involves surrounding the base of a pole with a steel casing that is screwed into the ground, compacting the soil and creating an annular space around the pole that is filled with a fast-setting resin mixture. Two types of fumigants are used to halt fungal activity and prevent its recurrence. The result is a permanent solution to groundline deterioration in that the life expectancy of a pole after treatment is determined by the durability of its remaining top portion. Two companies have already licensed this EPRI technology and are providing it to major utility contractors throughout the United States.

Golden opportunity

Wood utility poles must stand up to a variety of environmental assaults. Termites chew on them. Motorists ram into them. But most important, moisture at the groundline creates suitable conditions inside the poles for the growth of fungi. These microorganisms secrete enzymes that can digest the cellulose in wood, making it crumble. Advanced stages of fungal attack are clearly visible from discoloration of the wood (brown rot or white rot), but often the most severe damage is hidden in the very heart of a pole and may escape detection for many years. By the time such a pole is inspected by core drilling or sounding with a hammer, its structural integrity may already have been severely compromised.

If deterioration has not advanced too far, a pole can often be reinforced. Until a few years ago reinforcement was usually accomplished by strapping the weakened pole to a wood stub placed in the ground beside it. The appearance of this crutchlike arrangement prompted considerable public dissatisfaction, however, and utilities in urban areas often had to replace poles rather than stub them because of residents' complaints. Steel channels that could be driven into the ground snugly against a damaged pole have proved to be more esthetically acceptable and less expensive to install, but the life extension they provide to a pole is still limited by continuing groundline deterioration.

When pole weakness at the groundline is substantial, replacement has usually been considered inevitable. Such a step can be an expensive proposition, however, involving not only new materials but also a substantial labor commitment and interruption of service. Replacing a simple distribution pole with easy equipment access can cost \$800–\$1000. If transformers have to be removed or if access is difficult, the cost can rise to \$2000–\$3000. And replacing the pole of a transmission line may cost well over \$4000.

It was against this background that EPRI launched a project with Kinnan and Associates to develop a foundation system that could be used to both anchor transmission towers and repair badly damaged wood poles. In both cases, research indicated the importance of using a tapered metal sleeve with helical grooves or extensions that would allow it to be screwed into the ground. This action, it was found, compresses the surrounding soil and substantially enhances its reactive strength. The metal casing, similar to culvert pipe but having a taper along its leading edge, is easily manufactured and an appropriate insertion mechanism can readily be mounted on the frame of a truck or forklift.

As this technology development progressed, recalls Program Manager Richard Kennon, "we gradually realized we had discovered a golden opportunity for technology transfer. Utilities were purchasing about eight million wood poles each year, with perhaps half of them needed for replacements. When it began to appear that we were developing a highly reliable, cost-effective alternative to pole replacement, utility interest soared."

The structural behavior of poles repaired using the system developed by Kinnan was evaluated at special test facilities at Colorado State University. A variety of destructive tests have been conducted in situ and in the laboratory to see if the repair method would meet standards set by the National Electrical Safety Code. In addition, data were collected on installation time, sleeve configuration, and methods of installation. These tests generally indicated that the repair system could be installed in less than an hour and would indeed restore the groundline region of the pole to its original strength. (Some problems were encountered in determining the exact strength of the repair region because of weaknesses in other areas of the aging poles used in the tests.)

Steps toward commercialization

On the basis of the EPRI research, Utilitech, Inc., of San Ramon, California, decided that the repair method showed considerable potential. The company obtained a license from EPRI in 1983 and began its own development work to bring the method to full commercialization. One improvement Utilitech made was to split the metal sleeve lengthwise into two half-cylinders that are bolted together around the base of a pole before being driven into the ground. This arrangement allows installation of the sleeve without shearing off the pole at ground level, as in the original design.

Utilitech patented this improvement and entered into an agreement with EPRI that enables the Institute to license the improvement as part of the basic repair system.

Utilitech's tradename for its implementation of the repair system is Repol. The device incorporates a steel casing with a helically corrugated, tapered bottom. The Repol sleeve is screwed into the ground, using a special Utilitech boom mounted on a truck. Since Repol's introduction in 1984, more than 2000 wood poles have been treated, and the company expects that its technology will be licensed by contractors in all 50 states by the end of 1986.

A second EPRI licensee is Loadmaster

Permanent Solution to Decay

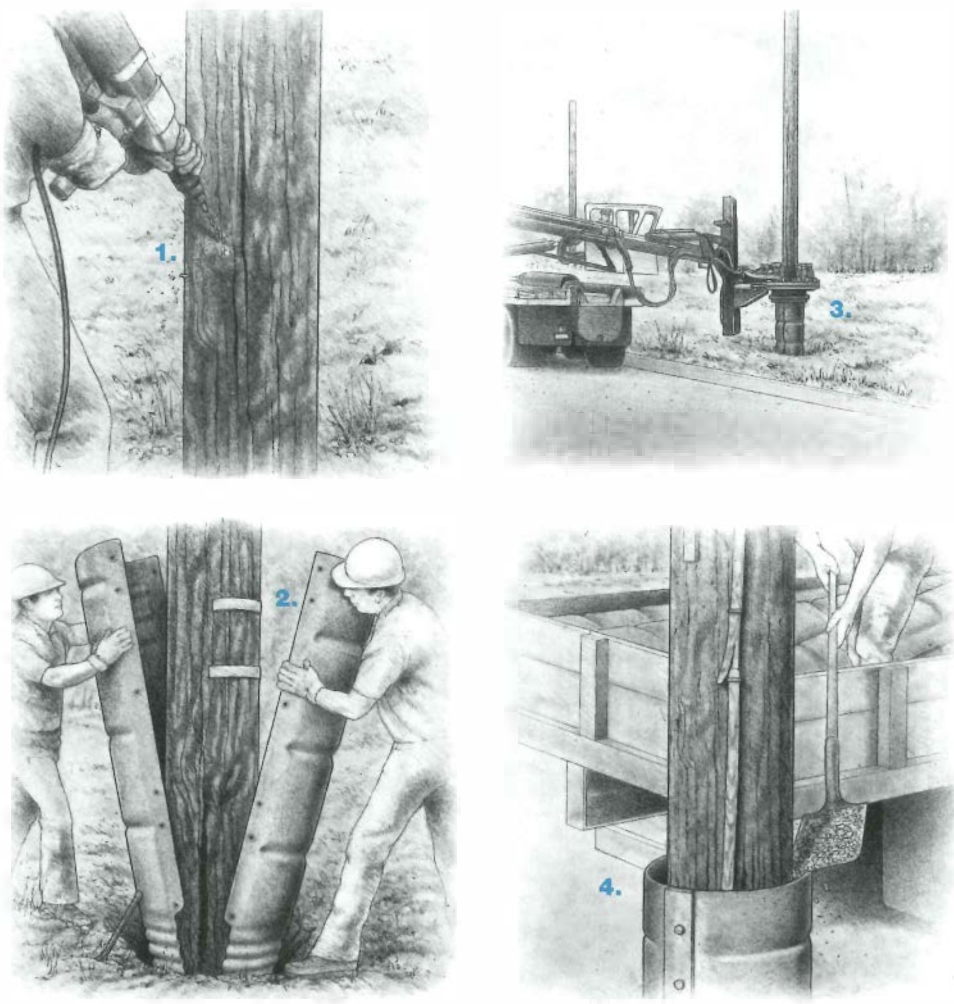
A wood utility pole damaged internally by fungal decay can often be repaired permanently by using an EPRI restoration system—for about half the cost of pole replacement. The repair, which restores original groundline strength to a pole, may take less than one hour to complete and involves four basic operations.

1. An advance crew exposes the decayed region and treats the pole with a liquid fumigant.

2. The repair crew positions a split metal casing around the pole and bolts the two sections together.

3. Helical contours around the tapered base of the steel casing enable it to be augured into the ground, compacting the soil around the base of the pole.

4. The annulus between the steel casing and the wood pole is filled with alternating rings of epoxy resin and aggregate, enclosing a strip of slow-release fumigant to prevent further decay.



Systems, Inc., which markets its version of the repair system under the tradename Nu-pole. In this implementation, the sleeve bottom has two inwardly bent tabs and welded helical strips to provide soil compression. An auguring device mounted on the body of a forklift-type vehicle is used to screw the Nu-pole casing into the ground.

Specific technical requirements for using the repair system are generally similar for the two licensees. Utilitech requires that the casing diameter be 5 in (127 mm) greater than the diameter of the pole for most wood species, but a Western red cedar pole needs a 7-in (178-mm) margin at the groundline because of its tendency to swell. At least 40% of the cross section of the pole must be sound at a point 18 in (457 mm) below the top of the Repol casing.

Loadmaster typically requires that the steel casing diameter be at least 5 in larger than the diameter of the pole and that core samples be taken to reveal the extent of deterioration. The suitability of a pole for repair is then left to the utility; Baltimore Gas and Electric Co., for example, requires a shell of sound wood at least 2 in (51 mm) thick at the top of the casing.

In both implementations, chemicals are used to stop fungal activity in damaged portions of the pole and protect the portion of a pole encased in the metal sleeve. The protective action of the chemicals may last much longer in this method of pole repair than in other methods because the chemical vapors are essentially sealed into the wood by the surrounding material.

Once the casing has been set and the chemicals added, the annulus between the pole and metal sleeve is filled with alternating rings of epoxy resin and gravel. At the top, a watershed is formed by a mixture of epoxy resin and sand, effectively sealing the annulus. The resin mixture is designed to harden before the installation crew leaves the site, and when the resin has cured fully, the shear bond formed is so strong that failure occurs first in the wood. Because of the strength of this bond, a pole can be reset, if necessary. A tilted pole, for example, can be straightened or a pole next to a curb can be set off-center in the sleeve without impairing the groundline integrity of the repair. Often a pole can also be raised a foot or two during restoration.

Utility applications

Studies conducted by the two licensees indicate that Repol and Nu-pole have the potential for providing considerable cost savings to utilities in the near term. Both companies report that their systems can generally be installed for less than half the cost of pole replacement. Depending on the size and placement of a pole and the amount of equipment mounted on it, installation of a permanent groundline restoration system may cost approximately $600–$1100. Utilitech reports that its clients have found that pole restoration becomes more cost-effective than replacement if the expected life extension of a pole is as little as two years.

Perhaps the most stringent utility test of the Repol system was conducted recently by Southern California Edison Co. A 70-ft (21-m) cedar pole with a deteriorated base was removed from service and reset at SCE's Villa Park substation for testing. A Repol unit 26 in (660 mm) diam, 10 ft (3 m) long was used to repair the pole. Although the original setting depth for this pole was 11 ft (3.4 m), soil at the substation was so hard that its new depth was restricted to 9 ft (2.7 m). The bottom of the Repol casing reached 4.5 ft (1.4 m) below the groundline. Installation time was nearly four hours because of the hardness of the earth, compared with less than an hour reported at easier sites.

A cable was attached to the pole about 1 ft (0.3 m) below its top and rigged to the frame winch of a transmission line truck. The pole was then pulled to a tension of 1000 lb (4 kN) and held for 10 minutes, which produced only a hairline crack in the epoxy. At a tension of 2000 lb (9 kN) the pole deflected more than 7 ft (2 m) from vertical alignment but produced no further change in the repair section. Finally, at 2800 lb (12 kN) of tension the pole deflected nearly 11 ft (3.4 m) and snapped at mid height. According to the National Electrical Safety Code, a new 70-ft (21-m) pole should be able to withstand 3700 lb (16 kN) of tension, while a replacement pole is required to withstand only 2467 lb (11 kN). The test pole thus performed well within the replacement standard, and when it failed, there had not been any structural damage to the repair section.

An economic analysis of the Nu-pole system, performed by Arizona Public Service Co. in 1985, indicated the magnitude of savings that may be expected from the pole restoration technology under realistic utility conditions. The company found that it saved an average of $1400 per pole by using the repair method, compared with pole replacement. Because of these savings, APS expected to use Nu-pole on about 160 poles in 1985 and on another 100 poles this year. Through such a restoration program, the company hopes to extend the life of wood poles to 50 years or more, instead of having to replace them after only 30–35 years of life.

A question of quality

"Recent utility applications of the pole restoration technology developed by EPRI have confirmed our best hopes for the system," says Kennon. "It's a question of quality. Utilitech and Loadmaster have worked hard to keep quality high, and tests under realistic utility conditions have clearly demonstrated the advantages of this approach. Previously, utilities have had to either replace deteriorated poles or accept repairs that were clearly temporary. The EPRI repair system gives them a very attractive third choice—permanent restoration of groundline integrity and significant extension of pole life." ■

This article was written by John Douglas, science writer. Technical background information was provided by Richard Kennon, Electrical Systems Division.

Electric ARM Works Hard for Utilities

Often required by regulatory agencies, end-use monitoring studies are being used to assess the performance of energy-efficient appliances or equipment, to gather data on specific equipment loads, and to monitor total customer energy consumption. The electric appliance research metering system, also known as the Electric ARM, was developed by EPRI in 1983 with just such utility needs in mind. Eight utilities contacted across the country are now using or are planning to use the Electric ARM in a wide variety of end-use studies.

Installed as a smart extension cord between individual appliances and the wall outlet, ARM can continuously monitor individual appliance loads and transmit the data through existing house wiring to a receiver. The receiver sends the data by hardwire connection to a nearby pulse recorder that stores the data in a time-related format. This device has been available for several years from EPRI's licensee, Robinton Products, Inc., and utility experience shows it to be a versatile and dependable tool that minimizes inconvenience for study participants.

The majority of ARM applications to date involve studies being carried out in the residential sector. For example, Public Service Electric and Gas Co. (New Jersey) monitored 100 new refrigerators supplied to residential customers as part of a one-year study of high-efficiency and standard refrigerators of various capacities. Similarly, Atlantic City Electric Co. used the Electric ARM in an 18-month study to examine the load shape profile of frost-free versus manual defrost refrigerators.

Niagara Mohawk Power Corp. first employed ARM in a 15-month study of electric water heaters, ranges, and refrigerators. The utility now has a 140-site residential study under way that covers a greater variety of appliances, in addition to the total building load. Later this year Pacific Gas and Electric Co. also plans to use ARM in a residential study of major appliances, such as refrigerators, microwave ovens, and window or wall air conditioning units.

In one of the largest studies of this kind, Southern California Edison Co. (SCE) is applying ARM in 250 residences over several years. Each site produces data from the entire house and from three pieces of household equipment out of a total of 14 that are being studied, including evaporative coolers, dishwashers, waterbed heaters, and electric spa pumps in addition to more-common appliances.

Besides surveying household end use, SCE is using ARM to find out whether an economizer feature in a central air conditioning system will affect peak load. SCE installed this new central heating and air conditioning equipment at 18 sites in a study that will last for several years. Also on the heating and cooling side, Mississippi Power Co. is completing a residential study of waste heat recovery from heat pumps.

The Electric ARM has opened the door to commercial and industrial end-use studies, where the diversity of equipment has always presented a challenge. In addition to monitoring 500 various residential loads, Sierra Pacific Power Co. leads the industry in its use of the ARM pulse transponder on 480-V polyphase circuits as part of a monitoring system for large loads in commercial buildings. The utility arranged for a communication hardware supplier to furnish the custom signal bridge devices required for this application. In mid 1986 Niagara Mohawk will begin a 200-site study of small and large commercial and industrial buildings, focusing on electricity use for air conditioning, heating, lighting, and manufacturing machinery.

Single- and polyphase equipment, such as copy machines, compressors, and lighting, are the target of an SCE study at 50 commercial sites, which is slated for the third quarter of 1986. And Atlantic City Electric will also study commercial and industrial sites later this year, looking at total load as well as air conditioning, lighting, and non-process-related water heating.

Farms have always presented special end-use monitoring problems because of the variety of equipment involved and its highly dispersed locations on the farm. The Electric ARM appears to be particularly well suited for such applications. Niagara Mohawk is beginning a study of 40 vegetable, dairy, and poultry farms over an 18-month period. The utility will monitor the farmhouse load, as well as seven selected items of electric farm equipment.

Load management specialists in utilities across the country agree that the Electric ARM is reliable, reusable, and easy to install. Earlier efforts to monitor end use were expensive and complicated, requiring insertion of watthour meters into circuit wiring and the running of wires from the meter locations to a pulse recorder. Utility acceptance of ARM has been enthusiastic, and the device has received particularly high marks on practicality. Laboratory tests by Georgia Power and SCE, as well as checks of ARM installations by Public Service corroborated the manufacturer's specifications for excellent accuracy.

EPRI licensee: Robinton Products, Inc., 580 Maude Court, Sunnyvale, California 94086

Utility Contacts

Atlantic City Electric Co., Richard Goodleaf; Georgia Power Co., Randol Farlow; Mississippi Power Co., Lee Welch; Niagara Mohawk Power Corp., Neil Bourcy, Peter Eppolito; Pacific Gas and Electric Co., Leslie Guliasi; Public Service Electric and Gas Co., Charles Gentz; Sierra Pacific Power Co., Jack Finger; and Southern California Edison Co., Harwood B. Fowler, Susan Kappelman, Mark Martinez. ■

Improved *EPRI GUIDE* Published

The Institute has recently published a new edition of the *EPRI Guide*, which provides ready access to EPRI's research results and information resources. The new *Guide* is being offered in an improved, four-volume format: *Technical Reports, 1982-1985; Computer Programs and Databases; Licensable Inventions;* and *Communications Resources*. Available as a set or separately, the four *Guide* volumes will be updated and reissued three times a year. A retrospective volume of the *EPRI Guide* is also available that covers the remaining EPRI technical reports, published from 1972 through 1981.

This new edition of the *Guide* is easier to use and provides more information than in the past. The subject index has been expanded, and abstracts are now furnished for all technical reports, not just recent additions. The *Communications Resources* volume provides descriptions of available audiovisual and print media materials, including abstracts of all *EPRI Journal* feature articles. Copies of the *Guide* can be ordered from the Research Reports Center, P.O. Box 50490, Palo Alto, California 94303 (415-965-4081). Although there is no charge for the four-volume set, the retrospective volume of the *EPRI Guide, Technical Reports, 1972–1981*, is priced at $35.00 for non-EPRI members.

The *Guide* information is also stored in a single data base, PUBS, which can be accessed directly. PUBS is updated continuously, and the 30 utilities that already use this data base on their computers have found it to be valuable and easy to use. PUBS is also available as a subfile of the Electric Power Database (EPD) and is available for general on-line access through DIALOG Information Services. Information on accessing EPD and PUBS can be obtained by calling the EPRI Hot Line (415-855-2411).

In a further move toward user flexibility, EPRI is seeking member utilities to test MICRO PUBS, which offers the *Guide* information on PC diskettes that can be used as floppies or to load to hard disks. Seven diskettes are available, one each for the four *Guide* volumes and the three results documents: *Ready Now, First Use*, and *Off the Shelf*. ■ *EPRI Contact: Joseph Judy (415) 855-8936*

RRCS Simplifies Coal Transport Costing

A new tool now available to utility economists and fuel supply planners can help take the mystery out of coal shipping costs. The rail routing and costing system (RRCS), an interactive, menu-driven software package, allows the planner to review the available rail routes from mines to power plants and to assess the carrier's transportation costs for each.

RRCS's transportation network is modeled to include all the elements involved in moving coal by rail from a mine to a power plant: rail junctions, single- or multiple-track rail lines, and local pickup and delivery options. Adjustments can also be made for characteristics of specific commodities, such as general freight, carload coal, and unit train coal. RRCS estimates both fully allocated and variable costs.

After reviewing all options, the shipment routing module selects the most suitable route, considering elements such as energy costs, crew wages, track maintenance costs, and rail line ownership. New information is added to the data base by the network data management module; the planner can use this module, for example, to add shipment destinations and connecting rail lines not included in the original data base.

Although the model is designed primarily for costing coal shipments, its flexibility allows its application to the transportation of other products, such as chemicals used in flue gas desulfurization, or the assessment of the effect of large energy issues, such as acid rain, on coal transportation routes and costs.

The RRCS code now runs on CDC Cyber machines and requires two commercial support packages: SIMSCRIPT II.5 (CACI, Inc.) and RIM (Boeing Computer Services). A timesharing version of RRCS will soon be available through Boeing Computer Services. ■ *EPRI Contact: Edward Altouney (415) 855-2626*

R&D Status Report
ADVANCED POWER SYSTEMS DIVISION

Dwain Spencer, Vice President

GAS TURBINE DIAGNOSTIC INSTRUMENTATION

Hot section inspections and maintenance are the principal causes of utility gas turbine downtime. Efforts to improve turbine availability will benefit most from the development of diagnostic instruments capable of measuring the interrelationships between hot-section components and of detecting their degradation. Utilities will benefit from this development because using these instruments will help them to minimize planned outages and to avoid serious maintenance problems.

A multitask research effort aimed at the development of reliable diagnostic instrumentation for use in the hot-gas path of combustion turbines is under way (RP2102). An experimental monitoring system was installed in the hot-gas path of a turbine at Houston Lighting & Power Co.'s Wharton station. Gas turbine unit No. 41, on which the demonstration tests are being performed, is General Electric Co.'s Frame 7 (MS7001-B) heavy-duty industrial gas turbine with combined-cycle operation at a high service factor. This machine is one of eight arranged to form two STAG combined-cycle plants at the station. The field tests will be performed over a period of about two years, during which important data will be gathered on the durability and performance of the diagnostic instruments that compose the monitoring system. The data will be analyzed to obtain information essential to the development of algorithms for use in predicting the degradation of hot-section components. The overall objective is to develop on-line methods for determining maintenance requirements for utility gas turbines.

The near-term goals of the field test program are (1) to demonstrate the durability of the instruments and the validity of the data they produce (the design life of the instruments and sensors is currently 10,000 hours), and (2) to use the installed instrumentation and data acquisition system to locate and isolate operational problems.

The program's long-term goals are the following.

- To establish engine signatures by characterizing steady-state and transient operating conditions of the gas turbine engine
- To ascertain signs of degradation that can be used as indicators of hot-section integrity after trend analysis of the collected data
- To identify and characterize exceptional failures of gas turbine components; all events associated with a forced outage to be documented and correlated with data trends immediately preceding the failure

A data acquisition computer collects and compiles information from the diagnostic instruments, then transforms it into tables of engineering units and graphics. A team of data analysts subsequently correlates the results into relationships that characterize long-term component signatures.

This project is a team effort involving as many as 15 different contractors. In addition to the 5 contractors who have developed diagnostic instruments for the project, the team includes data acquisition experts, data analysts, and several contractors who have performed special installation services.

Instrumentation

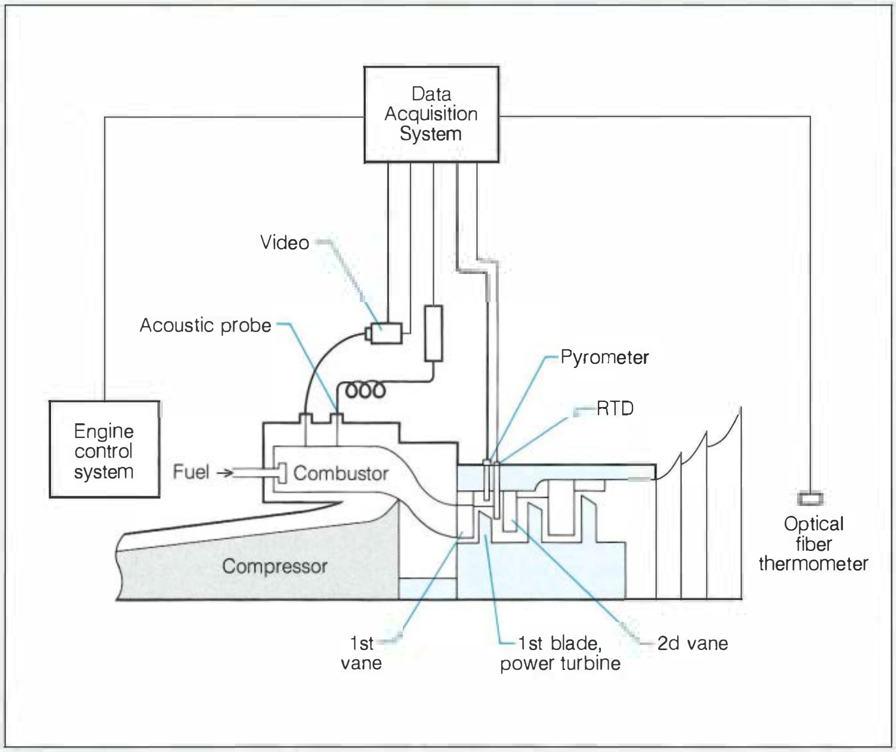
Five advanced diagnostic instruments were developed for specific application in the hot-gas path of a utility combustion turbine (Figure 1). These instruments are (1) a high-temperature resistance temperature detector, or RTD (Kaman Instrumentation) to measure gas temperature at the first-stage turbine rotor; (2) an optical-fiber pyrometer (Solar Turbines, Inc.) to measure first-stage turbine blade temperatures; (3) an optical-fiber combustion viewing system (United Technologies Research Center) to provide temporal and spectral information on flame quality and stability; (4) an acoustic probe (Battelle, Columbus Laboratories) to measure acoustic pressure variations in the gas turbine hot section; and (5) an optical-fiber thermometer (Accufiber, Inc.) to measure fluctuations in exhaust temperature.

The RTD is installed just behind the first-stage turbine blades and immediately ahead of the second-stage stationary vanes. The intent is to collect data on gas temperatures in the range of 1000–1800°F (538–982°C) by sensing changes in the resistance of a specially calibrated coil made of a tungsten-rhenium alloy. The chosen RTD was originally used to make precise measurements of high temperatures in nuclear fuel rods. In the gas turbine, however, the environment is more turbulent, and the probe is exposed to high pressures, high flow rates, and high bending moments. Therefore, a sheath thick enough to withstand the bending loads was placed around the probe; considerable care was taken to ensure the compatibility of materials.

In the pyrometer, a lens assembly collects information and sends it through an optical fiber cable to a photodetector calibrated to relate the signal to the metal temperatures of the turbine blades. Metal temperatures may be expected to vary considerably from point to point on a single blade. Therefore, it is necessary to examine temperature profiles of individual blades and from blade to blade on a given wheel to determine whether any blades are significantly hotter than others (Figure 2). Hot blades generally result from improper cooling, which may be pinpointed by this measurement.

The combustion viewer uses a TV link to provide visual information on the flame. The probe has a lens assembly with a 120° field of view of the flame pattern over a 10-in (254-mm) combustor section (looking downstream toward the turbine blades). The image is focused onto a 10-in-long optical-fiber bundle that contains 70,000 fibers. This bundle couples to a 15-ft-long (4.6-m) image guide capable of high-resolution optical transmission. The image beam is focused either onto a camera system or onto a seven-element photodetector, which is moved in and out of the light beam. When

Figure 1 Diagnostic monitoring system for the hot-gas path of a utility combustion turbine (engine cross section). The system comprises five instruments: a combustion viewer (information on flame quality); an acoustic probe (pressure variations in hot section); an optical pyrometer (first-stage turbine blade temperature); a resistance temperature detector, or RTD (gas temperature at first-stage turbine rotor); and an optical-fiber thermometer (fluctuations in exhaust temperature).



the camera is in the circuit, it sends a video signal to a monitor. The signal is digitized to provide inputs to a 64 × 64 pixel array. Because each pixel has an intensity level related to that found in the original flame, it is possible to record combustor flame images and to calculate flame geometry on the basis of those images. These computations can then be related to reliability considerations. When the camera is moved aside, the beam is sent to a smaller, 7 × 1 pixel array used to generate analog signals representing flame wavelength spectra and a time-varying signal representing flame intensity fluctuations (flicker).

The acoustic probe is a piezoelectric transducer mounted in a piece of anechoic (i.e., echo-free) tubing to determine whether monitoring acoustic outputs from the turbine combustor can provide data useful in efforts to improve turbine reliability and performance. Acoustic patterns may be related to flame phenomena or to other internal events; data correlations may reveal whether low-frequency pulsation or combustion instabilities are causing problems.

The optical-fiber thermometer uses a sapphire rod to measure temperature primarily on the basis of thermal radiation rather than on conventional heat transfer. It is expected that the device will provide extremely fast, highly accurate measurements of temperature fluctuations. Data may be obtained over a wide frequency range. Therefore, the device is being used initially to monitor fluctuations in the turbine exhaust. If suitable results are derived, measurements will be performed in more-critical areas, such as the combustor exit or turbine inlet regions.

Outlook

The field test is expected to validate the diagnostic instruments that have the greatest potential for gas turbine applications in the utility industry. From this study EPRI plans to develop methods of data analysis and correlations to identify equipment degradation for an effective system of failure avoidance. Additional diagnostic instruments are being considered for field test at the Wharton station, such as optical-laser devices for on-line measurement of rotating metal clearances at blade tips and other internal points.

EPRI is also planning durability tests of early advanced-technology gas turbines installed in

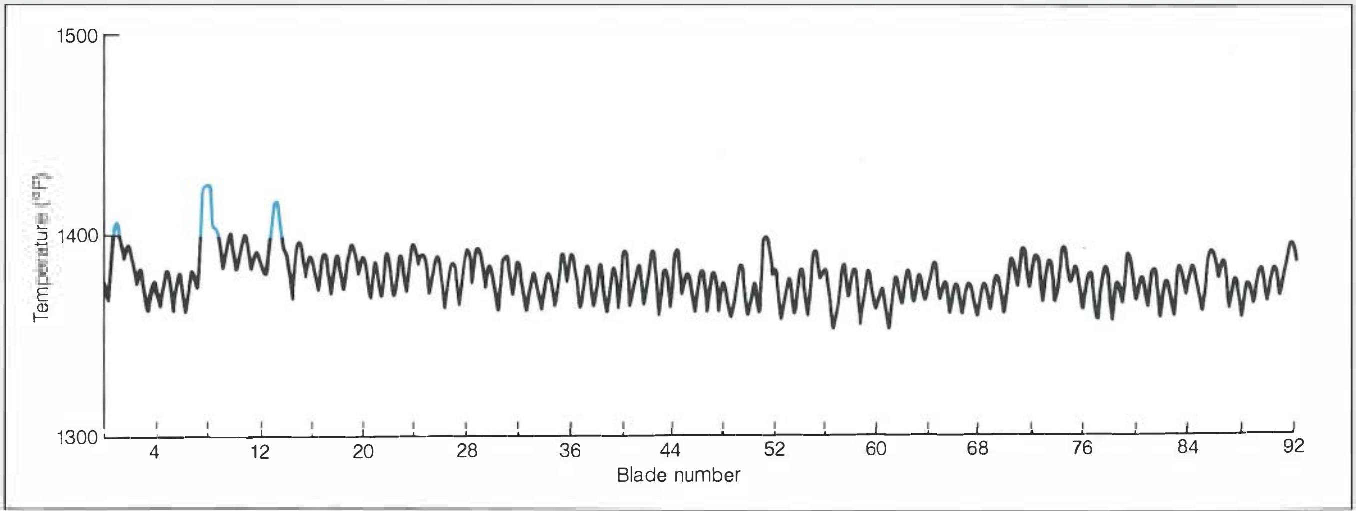


Figure 2 First-stage gas turbine blade temperature profile. The temperatures shown across the 92 blades of the first-stage turbine rotor have been averaged over a 5-min period. Three blades appear to be hotter than the adjacent blades (above 1400°F).

electric utilities. The current field test is thus a precursor of future projects by developing the general methods and instrumentation that will be required for comprehensive data analysis. *Project Managers: Leonard C. Angello, George H. Quentin*

WOOD CHIP FUEL IN A CIRCULATING-FLUID-BED GASIFIER

The U.S. utility industry has expressed continuing interest in increasing the use of biomass (principally wood) as a fuel for power plants. Gasification is an intermediate step in several advanced (other than direct combustion) approaches that are being evaluated for the small plant sizes expected for biomass-based power generation. Among gasification approaches, the circulating-fluid bed being developed by Lurgi has several advantages, including the ability to handle a range of feeds while producing negligible tar. Behavior of typical wood chip fuel from the Pacific Northwest was tested by gasifying 180 tons of this material at the 1.5-MW (th) Lurgi pilot facility in Frankfurt, West Germany. EPRI and the Bonneville Power Administration (BPA) sponsored the tests, and Lurgi shared the cost. Performance was excellent. No tars were formed, and (as expected) sulfur and ammonia levels in the product gas were minimal. These findings confirm the advantages of circulating-fluid-bed gasification for application to biomass-fueled generation approaches.

Biofuels, principally wood, are estimated by the U.S. Department of Agriculture (USDA) Forest Service to provide 3–4% of the primary energy in the United States. In recent EPRI-sponsored polls and in such documentation as EPRI AP-2320, a number of utilities have expressed interest in the greater use of biomass as a generating fuel. In addition, a recent plant-by-plant survey of generating facilities indicates that biomass-fueled capacity already exceeds 1000 MW—and it is increasing rapidly.

Although it provides opportunities for the electric utility industry, biomass has a limitation. Supply constraints at any one site usually dictate that biomass-based power plants be small, with capacity generally expected to range from 100 MW (e) down to less than 10 MW (e). The size range for biomass plants is consistent with utility desire to add capacity in smaller increments, but conventional direct-combustion-based generating methods become less efficient with decreasing scale. Thus, EPRI's biofuel research is examining other approaches that promise improved performance at these smaller scales.

Several approaches (including internal combustion engines, fuel cells, and combined cycles) require that biomass fuel be gasified as an intermediate step. Recent attention has focused on the Lurgi circulating-fluid bed (CFB) because of the commercial status of CFB for combustion, the ability of CFB to produce tar-free gas, and the ability of CFB to accept a range of biomass feeds, as well as coal. EPRI's Solar Power Systems Program recently helped to fund testing the performance of wood chip fuel from the Pacific Northwest in the 1.5-MW (th) Lurgi circulating-fluid-bed pilot plant in Frankfurt, West Germany (RP2612). U.S. lignite coal was also gasified, and the project was carried out cooperatively with the EPRI's Clean Gaseous Fuels Program (RP2656). Major cofunding was provided by BPA, and Lurgi shared the cost. The objective was to obtain design-point gasification data, including biomass throughput, product gas composition, and carbon conversion.

CFB gasification

A CFB gasifier is distinguished from other types of fluidized-bed gasifiers by the magnitude of the fluidizing gas velocity. Gas velocity in the CFB is above that of a conventional fluidized bed (where nearly all particles remain in a well-defined bed) but below that of an entrained, or transport, reactor (where particles react while suspended in the gas stream). Such intermediate fluidizing velocities result in uniform temperature throughout the reactor and in excellent heat and mass transfer within the bed.

Bed material is typically fuel and fuel ash, with limestone added when needed for sulfur capture (e.g., with coals). For heterogeneous fuel and ash particle-size distributions typical of biomass applications, the larger fuel and ash particles remain in the bed, while smaller particles leave entrained in the product gas stream and are captured (generally by cyclones) and returned to the reactor. High gas production rates and carbon conversion are afforded with small unit sizes. The reactor can accept a range of fuels—biomass or coal—in terms of combustion characteristics and particle sizes, which is important for biomass applications. In addition, CFB overcomes the problems of tar production and inability to accept fines, which characterize moving-bed gasifiers of the Wellman-Galusha type. By accepting a range of particle sizes, it avoids the expensive (for biomass) size reduction required by entrained units.

The CFB test facility in Frankfurt, West Germany, is a nominal 1.5-MW (th) unit owned and operated by Lurgi. It has been used to evaluate the gasification and combustion characteristics of a variety of fuels, mostly coals. However, other applications have demonstrated the facility's versatility. For example, it has been used in tests (by a private sponsor) of livestock manure as a fuel for electric power plants.

The test facility consists of a gasifier 0.7 m (2.3 ft) in diameter and 10 m (33 ft) high (Figure 3). Screw feeders transfer the fuel from weigh bins to the gasifier. Other screw feeders introduce recycle material and limestone (when needed for in-bed sulfur capture). Raw gas leaving the gasifier passes through cyclones; ash and unburned fuel fines removed in the cyclones are recycled to the gasifier. Gas from the cyclones enters a gas-cleaning unit where it is quenched and scrubbed before disposal in a separate incinerator. The test facility is equipped with standard monitoring equipment for measuring temperatures, pressures, flows, and other process conditions. A series of thermocouples monitors temperatures at various locations in the CFB. An automatic data logging system records these measurements for subsequent analysis. The Lurgi laboratories are fully equipped for necessary analyses, such as particle-size distribution, fuel and ash composition, and gas stream components.

Gasification with wood chip fuel

The fuel used in these tests was chipped wood residue. This specific residue consists of branches, treetops, and other material left in the forest after harvesting merchantable logs, and it is known as yarded unmerchantable material, or YUM. The YUM residue, primarily from Douglas fir, is a by-product of normal timbering operations in western Oregon. Surveys by the USDA Forest Service show that on a dry basis, over 10 million tons of YUM are generated annually in the states of Oregon and Washington and that well over 100 million tons are produced nationwide. Thus, this by-product represents a material available in large quantities.

An EPRI contractor, Thomas R. Miles, Sr., who coordinated the efforts of contract chipping, trucking, and steamship companies, supervised the fuel acquisition (RP2612). The contract chipper, Fuels and Fire Management, Inc., chipped wood at residue sites in the Mt. Hood National Forest, following normal commercial practice. Chipped wood was continuously blown into open-top vans, which carried the chip fuel to a dock in Portland for transoceanic shipment. Despite snowstorms, which complicated efforts, the wood was delivered on schedule to Frankfurt, Germany. Table 1 gives the results of the chip fuel analysis.

Unlike coal, wood is generally available at relatively high levels of moisture, often close to

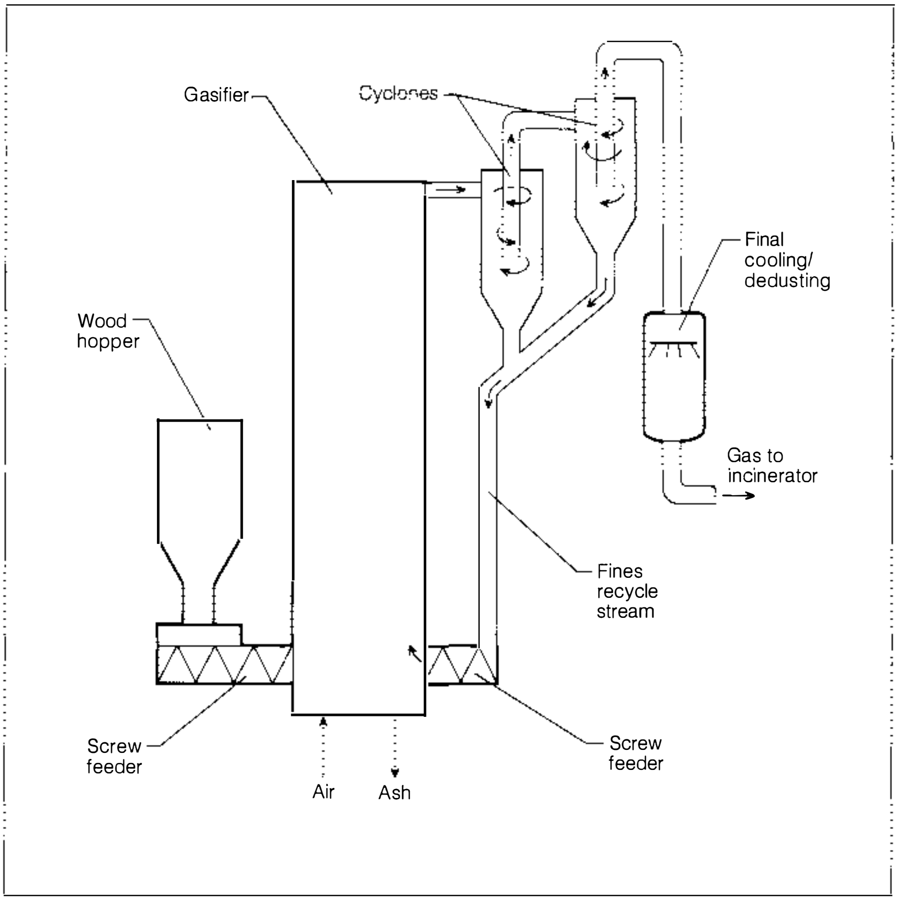


Figure 3 Schematic of circulating-fluid bed at the test facility. On the basis of gasification test results with wood, a commercial-scale wood-fired plant is expected to yield a 190-Btu/ft³ product gas and achieve carbon conversions close to 98%.

Table 2
TYPICAL GAS COMPOSITION

Component (vol%)		*Test Data
N_2	47.1	*Gasification, 816°C (1500°F)
CO	18.7	Air blown
CO_2	14.7	Wood moisture, 14 wt%
H_2	14.1	Wood throughput, 266 lb/ft² · h or 1298 kg/m² · hr, (dry basis)
CH_4	3.5	
CnHn	1.3	
H_2S	0.0036	
COS	0.0004	

*Gas heating value, Btu/ft³ = 163.7.

50% for freshly harvested, or green, wood. Such moisture levels would significantly reduce gasification efficiency. However, gasification processes generally have ample reject heat available that can be used for drying, so for most of the tests, the wood was predried to a 10–20% moisture content to duplicate the predrying carried out at a commercial facility.

In general, test operations were smooth and covered the planned range of variables. During 150 hours of continuous run time, 11 different combinations of temperature, wood moisture, and throughput were tested. After attaining the desired conditions for each individual run, temperatures remained constant at all locations in the bed, and gas composition remained unchanged throughout the run. Table 2 shows typical gas composition. Generally, tar production was zero, and the production of intermediate molecular weight components (primarily phenols and fatty acids) amounted to less than one part in 10,000 by weight of the wood feed. As expected, ammonia nitrogen and sulfur (as H_2S and COS) in the product gas were minimal, reflecting low levels of bound sulfur and nitrogen in the wood. Without any further treatment other than particulate removal, the gas would be directly usable in many processes (e.g., without needing acid gas removal to meet emission standards). Wood throughput on a heating value basis ranged up to 40% more than that attainable with lignite coal, which reflects the higher reactivity of wood. Optimal gasification temperatures were similar, close to 815°C for wood and 830°C for lignite coal.

On the basis of the test results, Lurgi predicts that a commercial plant, fed wood dried to 15% moisture and operated under optimal conditions for wood, could produce a 190-Btu/ft³ product gas. For comparison, similar computations indicate that a lignite-fueled commercial CFB facility would produce a gas with a heating value of 183 Btu/ft³. Wood and lignite projections are compensated for pilot-scale heat losses, which were much higher than would be the case for a commercial plant. Carbon conversion for both cases is expected to be close to 98% for commercial-scale gasification.

Further work by Lurgi will include an economic analysis to accompany the above performance projections. *Project Manager: Don Augenstein*

Table 1
CHARACTERISTICS OF WOOD CHIP FUEL

Component (wt%)*		Composition (%)		Size Range (passing mesh, mm)	
C	51.3	Moisture, as received	30.0	30+	9
O	42.5	Volatiles (dry)	83.0	3–30	89
H	5.9	Fixed carbon (dry)	16.7	0–3	2
N	0.1	Ash (dry)	0.3		
S	0.1				
Cl	0.02				

*Heating value (dry basis) = 8700 Btu/lb.

R&D Status Report
COAL COMBUSTION SYSTEMS DIVISION

Kurt Yeager, Vice President

PCB CLEANUP

Polychlorinated biphenyls (PCBs) as a class of compounds have a high degree of public recognition. A PCB incident means television, radio, and newspaper coverage and increased public awareness of the related health and safety issues. The electric utility industry, as owner of the equipment in which most of the manufactured PCBs were used, bears the brunt of this public concern. Across the country utility programs are reducing the risks of PCB use, either by total removal of the compounds (by refilling or replacing equipment that contains PCBs) or by isolation techniques to reduce public exposure. Even if all this utility equipment is phased out of service, however, there will still be PCB-contaminated sites dating from the time when PCBs were not regulated, and as these are found, they will require corrective action. Technologies for cleanup are expected to be increasingly in demand as regulations, liability, and lack of suitable space reduce the acceptability of landfilling for the disposal of PCB-contaminated soil.

The currently acceptable options for dealing with PCB-contaminated sites are limited to excavation/landfilling and isolation. A draft report recently prepared for RP1263-19 describes experience with these options and summarizes rules and regulations, site investigation procedures, cleanup technologies under development, disposal facilities for PCB wastes, corrective action planning, and site cleanup requirements. One difficulty in dealing with site cleanup is the current lack of a consistent national policy. Given similar site conditions, different local views of acceptable risks may result in totally different cleanup requirements.

Removing PCBs from a site is a common option: contaminated soil is excavated and transported to a landfill for disposal. This option is costly because large quantities of soil must be transported in order to dispose of small quantities of PCBs. The landfill itself is not efficiently utilized, and the utility incurs a continuous potential liability for the PCBs at the disposal site. That liability issues from the Superfund regulations, which state that those who use a landfill have "joint and several responsibility" for cleanup if the site becomes an environmental hazard.

Isolation as a solution to PCB contamination of a site is less extreme than excavation. The objective is to contain the contamination and thus to eliminate exposure to PCBs. The weakness of this approach is that the site requires perpetual care and monitoring.

Currently, no processes are commercially available for the on-site treatment of PCB-contaminated soil. Two EPRI projects are addressing the need for this kind of treatment option. The first is developing a soil-washing process called Dirt Clean* (RP1263-15). Instead of landfilling material that is more than 99.9% soil, this approach involves removing the PCBs from the soil, concentrating them, and then dealing with them separately.

This project has evolved from laboratory bench-scale equipment to a laboratory pilot system with a 55-gal (0.21-m^3) capacity. In pilot testing, both spiked soil and utility-furnished contaminated soil from a site cleanup were treated with a proprietary mixed-solvent system. Batch washes were employed, with successive washes reducing the previous residual PCB level. Table 1 shows the results for eight runs.

As with any batch process, from a technical standpoint the limits of the Dirt Clean process are the limits of detection; that is, washing is repeated until there is no measurable change in PCB concentration. Each successive cycle removes fewer PCBs, however, and is therefore less efficient and less cost-effective. At some point the economics of the system will become unacceptable as lower and lower targets are set and the removal process becomes less and less efficient.

The current phase of this project entails process testing in a full-scale (commercial-size) unit, which has a capacity of 8 yd^3 (6.1 m^3) of soil. The contacting unit and the solvent recovery system were constructed as part of the project. In line with the concept of minimizing the volume of waste material for disposal, the used solvent is distilled to segregate the PCBs that have been removed from the soil; the PCBs can then be sent for incineration. It is expected that this system will have been demonstrated at a host utility site by the time this status report is published.

Besides proving that the system will work with field-size quantities of soil, the current demonstration will provide a realistic measure of the economics of the process—including man-hours expended per batch, processing time, and energy requirements. It is anticipated that after a successful demonstration the process will receive EPA approval. Plans then call for the treatment of 1000–2000 yd^3 (765–1530 m^3) of contaminated soil in an ex-

*Dirt Clean is an EPRI trademark.

Table 1
SOIL-WASHING TEST RESULTS

Run*	PCB Level (ppm) Initial	Final	Number of Washes†
1	41	0.18	3
2	492	0.69	10
3	67	<2.0	6
4	135	<2.0	6
5	1941	<2.0	12
6	910	<2.0	12
7	678	<2.0	10
8	16.4	<2.0	5

*Runs 1 and 2 used artificially contaminated soil; runs 3–8, utility-supplied soil from a contaminated site.

†I.e., the number considered sufficient to achieve the cited PCB result with the commercial solvent system; some runs actually involved more washes because the effectiveness of various solvent compositions was also being studied.

tended operation to assess equipment reliability. EPRI will also begin to seek potential licensees for the process at that time.

The second soil treatment approach being pursued by EPRI for PCB-contaminated sites is in situ vitrification (RP1263-24). In this process, originally developed under a DOE contract for the immobilization of low-level radioactive wastes, an electric current is passed through the contaminated soil to heat it to temperatures capable of melting it to glass and destroying the PCBs present (~1700°C). A preliminary experiment was performed with a 30-kW laboratory-scale system with 2-ft (61-cm) molybdenum electrodes and 9-in (23-cm) electrode spacing. The system operated for six hours, and the vitrified block formed to a depth of 32 in (81 cm).

One objective of the experiment was to observe whether there was significant migration of PCBs to cooler locales or whether PCBs were volatilized or were converted to polychlorinated dibenzofurans. (The system includes a hood and an off-gas collection system for capturing volatilized or modified PCBs.) Migration is not a major concern: no significant PCBs were detected in either the glass or the surrounding soil. Of the initial 8 g of the PCB used to spike the soil (Aroclor 1260), 4.2 mg were collected from the off-gas on florisil. The off-gas was also tested for dibenzofurans and dioxins; the measured quantities were 0.4 μg and 0.1 μg, respectively.

The projected economics of the process are competitive with excavation and landfilling. Depending on the cost of electricity and the amount of moisture in the soil, process costs can range from \$180 to \$360 per m^3 of soil (Figure 1).

The preliminary results show promise for in situ destruction of PCBs. EPRI plans to continue this work on a 500-kW system with 4-ft (122-cm) electrode spacing. An attempt will be made to obtain PCB-contaminated soil from a utility for the test. *Project Manager: Ralph Komai*

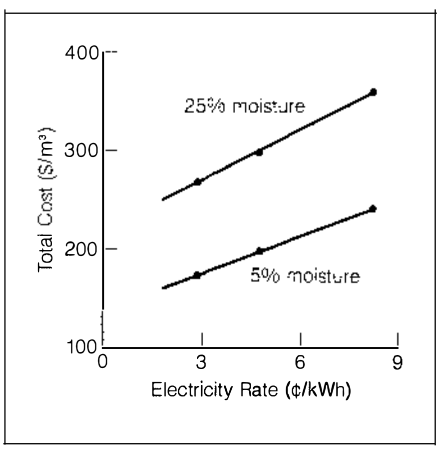


Figure 1 The cost of in situ soil vitrification depends on electricity rates and soil moisture content. When utility rates reach about 8.25¢/kWh, a portable generator becomes more economical for power supply, and the process cost levels off.

FGD CHEMISTRY

Flue gas desulfurization (FGD) involves several major chemical reactions and numerous minor reactions that can affect the process. For efficient FGD system operation, it is essential to understand the chemical reactions of a given process. Defining the chemistry of commercial aqueous FGD processes is the objective of RP1031 and RP1877. The ultimate goal of the projects is to produce a process simulation computer model.

FGD handbook

The major reactions involved in the various commercial FGD systems are fairly well known, but information on them was scattered and not readily available to utility personnel. Thus a high-priority task of RP1031 was to compile this information, and it has been published in EPRI CS-3612, Volume 1, *FGD Chemistry and Analytical Methods Handbook: Process Chemistry—Sampling, Measurement, and Laboratory Guidelines*.

Several major process variables or properties that can be used to define the efficacy of an FGD system are designated in the report as process performance indicators: sulfur dioxide (SO_2) removal efficiency, reagent utilization, liquid-phase alkalinity, relative saturation, and oxidation fraction. The report discusses each factor, covering its relation to performance and possible system problems, the calculation method, and the measurements required to determine its value. The report also makes suggestions about the design and operation of a laboratory to support an FGD system; sampling and analysis procedures and frequency; and sources of chemicals and equipment.

Chemical and physical analyses generally use well-known test methods, but the application of these methods to FGD process samples was not covered in the literature. Volume 2 of CS-3612 describes 54 chemical and physical test methods that can be used to develop data for calculating the FGD process performance indicators. For each method the report presents detailed procedures to be followed with FGD samples. Precision and bias were determined for each method, and accuracy was determined for those methods for which standards were available. Selected methods were subjected to an interlaboratory study, which is included in Volume 1.

Two of the process performance indicators, alkalinity and relative saturation, call for laborious calculations that require a knowledge of solubility product constants, ion pair formation, ion activities, and other factors. Therefore, a mainframe computer program developed for DOE was revised for operation on an IBM PC for utility use in calculating these indicators. Instructions for this software, called FGDLIQEQ, are presented in Volume 3 of CS-3612. The program uses data on FGD liquor composition to calculate ion balance (which indicates data accuracy); alkalinity, ionic strength, and SO_2 and carbon dioxide back pressure (which indicate the ability to absorb SO_2); and relative saturation and solid solution mole fraction (which indicate the solid phases that can precipitate). The relative saturation of gypsum ($CaSO_4 \cdot 2H_2O$) can be used to determine the potential for scale formation in a system, either in the scrubber or in the mist eliminator. FGDLIQEQ is available from the Electric Power Software Center.

All three volumes of CS-3612 are being revised to include data from laboratory, pilot plant, and commercial system testing completed since the handbook's publication. Laboratory studies have investigated the kinetics of sulfite oxidation, the crystallization of calcium sulfite and calcium sulfate, the formation of sulfur-nitrogen (S–N) compounds, the decomposition of such additives as adipic acid, the effect of high total-dissolved-solids (TDS) concentrations on FGD chemistry, and the effect of chloride concentration on SO_2 removal. In pilot-scale work, the effect of operating conditions on the rate of S–N compound formation has been investigated at the Arapahoe Test Facility wet scrubber, and data on limestone grinding were collected at several vendor laboratories. Commercial FGD system problems have been defined under RP2248-1. In several instances factors affecting operations required either laboratory or field testing, including the effect of magnesium ions in FGD liquors on the buffering capacity of dibasic acids, the effect of dissolved aluminum and fluoride on limestone dissolution, the effect of limestone particle size on limestone utilization, and the effect of washing gypsum solids on the concentration of impurities in the final gypsum product.

Analytical methods

In the interlaboratory study of wet chemical methods documented in Volume 1 of CS-3612, two methods showed large variations. These methods—one for chloride in a specific type of liquor and one for calcium and magnesium in limestone—are being revised to improve precision, and they will be included in the second edition of the FGD handbook.

A similar study has recently been completed for instrumental methods. The 30 participating laboratories (which included 21 utility laboratories) used eight methods involving atomic absorption spectrophotometry, ion chromatography, and specific ion electrodes. According to precision and bias calculations, the multilaboratory data showed greater variation than did the EPRI contractor's laboratory data (Radian Corp.) or the within-laboratory data from this study. For 25 determinations involving the eight methods and three types of samples (liquid, wet solid, and dry solid), the within-laboratory coefficients of variation were all less than 10% and in most cases were less than 5%. The multilaboratory coefficients of variation for six determinations were 10% or greater. The 21 utility laboratories had four determinations with coefficients of variation greater than 10%. Two methods, fluoride by specific ion electrode and calcium and magnesium by atomic absorption, had large bias values.

All the methods showing significant variation and bias are being reviewed to determine the cause; if method revisions are necessary, they will be completed for the second edition of the handbook. Also, analytical methods for S–N compounds, adipic acid decomposition products, several dibasic acids, and thiosulfate are being developed for the second edition.

Crystallization

In all lime and limestone wet scrubbing systems, the SO_2 absorbed is precipitated from solution as calcium sulfite/sulfate hemihydrate, $Ca(SO_3)_{1-x}(SO_4)_x \cdot ½H_2O$ (a solid solution with x variable up to 0.2), or calcium sulfate dihydrate, $CaSO_4 \cdot 2H_2O$ (gypsum). The basic data needed for a process simulation computer model, such as nucleation and growth rates and the effect of impurities on these rates, have been developed by the University of Arizona. These rates were found to vary with operating conditions. A study of the effect of additives on gypsum crystallization showed that citric acid modifies gypsum's crystal habit. These data are reported in CS-1885. Similar studies have been conducted for calcium sulfite/sulfate hemihydrate; the results will be published this year.

High TDS concentrations

Many utilities are limiting the amount of water discharged from power plants with FGD systems, and the concentration of soluble impurities in FGD liquors can increase dramatically when the loss of liquor is limited to that removed with the wet solids. In laboratory studies the effects of TDS concentration on SO_2 removal and solids properties have been determined over the range 30,000–250,000 mg/L. Magnesium chloride ($MgCl_2$), calcium chloride ($CaCl_2$), sodium chloride (NaCl), sodium sulfate (Na_2SO_4), magnesium sulfate ($MgSO_4$), or combinations of these compounds accounted for most of the TDS.

Gypsum crystallized from the high-TDS solutions was altered in crystal habit by all of the soluble compounds. Solutions with NaCl or Na_2SO_4 formed agglomerates of columnar crystals, whereas solutions with one of the other three compounds or with mixtures of all compounds produced single lamellar or acicular crystals. These crystal habits, if they prevail in a commercial system, will undoubtedly result in different crystal settling and filtration rates.

The effects of high TDS on SO_2 removal were studied in a bench-scale scrubber under identical operating conditions, again using the five compounds listed above. Test solutions were made by adding one of the compounds in increasing concentrations up to 120,000 ppm to a typical dilute scrubber liquor. Figure 2 shows that at concentrations to about 30,000 ppm, both sodium compounds and both magnesium compounds increased SO_2 removal, undoubtedly because of increased alkalinity in solution as sulfite ions. At concentrations above 30,000 ppm, all the chloride compounds caused a decrease in SO_2 removal, probably because of a decrease in sulfite ion concentration. These results were similar to those obtained by Babcock & Wilcox Co. and the Tennessee Valley Authority at the Shawnee station FGD pilot plant facility.

Sulfur-nitrogen compounds

When FGDLIQEQ was applied to data from routine chemical analyses of liquors from EPRI's integrated environmental control pilot plant and a commercial FGD system, the results did not show an ion balance; instead they showed more cations than anions. This lack of balance indicated that there was a problem with one or more of the determinations or that some chemical species had not been determined.

Subsequent analyses indicated that sulfur-containing compounds (other than sulfate and sulfite) were present that were not included in the normal method of total sulfur determination. These compounds were identified as S–N compounds formed by the reaction of nitrogen oxides and SO_2 in the scrubber liquor. The chemistry of these compounds is well known, and a number of S–N species are possible in this system. Analytical methods developed for all species will be presented in the revised handbook. Analyses of a number of liquor samples showed that hydroxylamine disul-

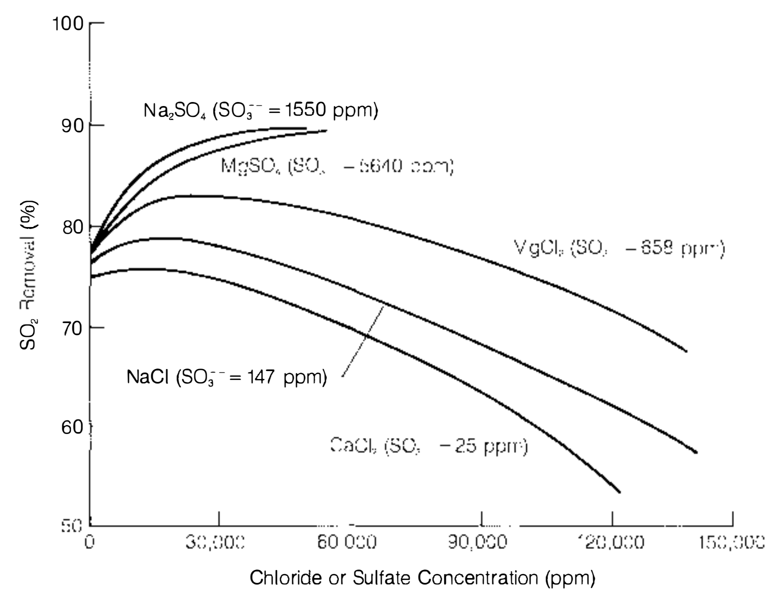


Figure 2 Effects of high TDS concentrations on SO_2 removal. In bench-scale tests five compounds were separately added to a typical dilute scrubber liquor to vary the TDS level. Sulfite concentrations at the end of the tests are shown in parentheses (higher SO_2 removal is associated with higher solution alkalinity as sulfite); the average baseline sulfite concentration was 160 ppm.

Table 2
SULFUR–NITROGEN COMPOUND FORMATION

Conditions of Tests (in order)	S–N Formation Rate (mol/d)
First baseline*	3.9
Low pH (5.2)	7.4
Mid pH (5.7)	4.7
High liquid/gas ratio (80 gal/1000 actual ft^3)	4.9
Second baseline*	4.2
High SO_2 (2000 ppm)	2.2
High Mg^{++} (150 mmol/L), natural oxidation	12.0
High Mg^{++} (150 mmol/L), forced oxidation	4.4
Third baseline*	5.4
Forced oxidation	1.6
Lime reagent, pH = 7	1.0
Lime reagent, pH = 7	1.9

*Baseline conditions: limestone reagent; pH = 6.2; inlet SO_2 = 500 ppm; natural oxidation; Mg^{++} < 30 mmol/L; liquid/gas ratio = 65 gal/1000 actual ft^3.

fonic acid (HADS) is formed first; depending on operating conditions, HADS can react further to hydroxylamine monosulfonic acid (HAMS) or amine disulfonic acid (ADS).

To determine the formation rates of these S–N compounds, the Arapahoe pilot wet scrubber was operated under a variety of conditions with limestone or lime as the alkaline reagent. Table 2 shows the test conditions and results. Baseline tests were conducted three times during the period to determine reproducibility. The third baseline test yielded a significantly higher result than the other two, which probably reflected uncontrolled variables, such as flue gas composition. Duplicate lime tests also showed variation in the S–N formation rate. In general, the formation rate of S–N compounds was highest under those conditions giving the greatest sulfite concentrations.

The pilot plant data were used to calculate the range of steady-state concentrations of S–N compounds. The effect of these levels on SO_2 removal was studied in a laboratory-scale scrubber. For concentrations up to 50 mmol/L (almost double the largest calculated steady-state concentration), SO_2 removal was not affected significantly. Even if the S–N compounds were to build to levels that can affect SO_2 removal, the problem could probably be alleviated by minor changes in operating conditions. When the Arapahoe pilot scrubber is available, further studies of conditions affecting S–N compound formation will be conducted.

Limestone reagent studies

The majority of FGD systems use limestone as the alkaline reagent. Limestone is widely distributed (CS-3618), and its properties can vary, depending on the geologic history of the formation. In an attempt to correlate the properties of limestone with its behavior in an FGD system, 30 high-calcium, dolomitic, and magnesian limestones representing a wide variety of geologic formations were sampled.

The grindability of limestone (i.e., the ease of grinding to −200 mesh) was found to be related to its macrocrystallinity (the extent to which the stone has individual crystallites greater than 5 μm). However, the test to determine macrocrystallinity is too time-consuming to be practical. Therefore, a grindability test that uses a laboratory ball mill was developed to compare limestones. This test correlates with the more elaborate and costly Bond Work Index.

Another property of limestone that affects its behavior in FGD systems is its dissolution rate. Many operating variables affect this rate; the major ones are scrubber liquor pH and limestone particle size. The dissolution rate increases with decreasing pH and particle size. The quantity of magnesium in the limestone can also have a major effect on dissolution: dolomite has a much slower rate of dissolution than calcite (high-calcium limestone).

All limestones respond by rapidly dissolving when ground to less than 325 mesh. Commercial tests at several utility FGD systems with different limestones indicate that reagent utilization can be increased to over 90% by grinding the limestone so that 90–95% passes 325 mesh. Pilot plant grinding studies have shown that although the finer grind requires more energy per unit of limestone, this increase is more than compensated for by better limestone utilization—that is, less limestone has to be ground.

A decrease in pH can also increase limestone utilization, but it can decrease SO_2 removal as well. In scrubbers with marginal SO_2 removal even with a fine limestone, SO_2 removal can be increased with a decrease in pH by adding dibasic acids as buffers in the system. Several commercial FGD systems have achieved excellent results by using this additive and optimizing other operating variables, such as limestone grind and pH.

Computer programs

FGDLIQEQ uses data on solution composition to determine several important performance indicators, but these calculations are not all that are needed to completely define FGD system operation. To help FGD operators calculate other performance indicators, computer programs for process data management, laboratory data management, and material balance are being developed for use on an IBM PC. These programs are being designed to interact with each other and with FGDLIQEQ.

An FGD process simulation model is also being developed on the basis of laboratory and pilot plant data. The bench-scale pilot plant recently constructed by Radian Corp. for installation at EPRI's High-Sulfur Test Center (HSTC) is now being used in Radian's Austin laboratory to provide additional data. The program will be tested for predictive accuracy at the pilot plant size at both Arapahoe and the HSTC when these facilities are available; this work is expected to start at the HSTC early next year. Finally, the program will be validated at several commercial FGD systems before publication. *Project Manager: Dorothy A. Stewart*

R&D Status Report
ELECTRICAL SYSTEMS DIVISION

John J. Dougherty, Vice President

DISTRIBUTION

Improved extrusion methodology

The objective of this project is to develop an improved method for preparing a superior cable by controlling the processing parameters in such a manner that voids and microvoids are reduced (RP1593). Pressure is controlled at the strand shield region during curing. This project was reviewed in the January/February 1983 *EPRI Journal*.

This research is concerned with hardware development, and not surprisingly, a number of hardware-oriented problems resulted during the earlier part of the project, which were eventually overcome. In recent months, several long lengths of cable were prepared both with and without controlled internal pressure at the strand shield region (Al conductor, 15 kV, XLPE insulation). The ac breakdown results on 100–150-ft (30–46-m) lengths revealed values ranging from 800 to 1400 V/mil, both for the experimental cables and for controls prepared on the same equipment.

Although results are promising, the principle of controlled internal pressure influencing ac breakdown on full-size cables prepared at conventional processing speeds remains to be conclusively demonstrated. This project will continue during 1987. *Project Manager: Bruce Bernstein*

OVERHEAD TRANSMISSION

Advances in full-scale tower testing

One of the primary purposes of EPRI's structural development projects and the Transmission Line Mechanical Research Facility (TLMRF) is to provide high-quality experimental data for evaluation and validation of the EPRI TLWorkstation* analysis and design software package (RP2016). An outgrowth of this need for large quantities of accurate data is the development of improved testing techniques, hardware, and computer software for full-scale testing of transmission structures.

Quality structural testing has been a part of the electric utility industry for more than 50 years. However, this full-scale testing has been geared to the requirements of proof testing, which does not normally require significant instrumentation. Fabricators and utilities do some structural testing that requires instrumentation, but these tests are normally developmental tests on structural components. Testing fully instrumented full-scale structures requires a level of test instrumentation not previously applied in the transmission line industry.

TLMRF is the most advanced transmission structure test facility in the world. Within practical limitations of time and money, TLMRF is providing the best experimental data for selected members or locations on a wide variety of structures. Considerable emphasis is placed on obtaining accurate and reliable data for the maximum number of members. Testing at TLMRF is completely automated. Load cells, winch controllers, strain gages, and other transducers collect the data and transmit them directly to a computer, which is programmed with the desired load cases, calibrations, and load limit information. The original TLMRF data acquisition system was built around a PDP11/23 computer, which was also used as a load control system for testing. In this configuration, 128 channels are available for all measurements; thus, approximately 80–120 channels are available for strain gage data or data from other transducers, depending on the number of load cells required for load application.

Because of the need to record data from any location on any tower, a data transmitter of unique design was selected; it is insensitive to the effects of lead wire length. A combination excitation supply and preamplifier was designed that could be situated in a small, weatherproof enclosure less than 3 ft (1 m) from any strain gage location. Signal output at the preamplifier is unaffected by changes in line length of 1000 ft (300 m) or more. A 50-Ω preamplifier output impedance and a 10-MΩ data system input impedance ensure that signal line losses are minimal, and shielded lines reduce noise pickup.

Although many member strain gage configurations are possible, two configurations have been selected as standard for most of the TLMRF lattice tower testing. A four-bridge arrangement requiring four data channels is used to measure combined force and moment in angle members. The procedure to compute the stress resultants (axial force and both bending moments) obtains the best least-squares approximation to the three stress resultants on the basis of the four strain measurements at each location. For members that are designed to carry tension only, or where the objectives do not require bending moments, a different gage arrangement is used. This second arrangement was suggested by the Bonneville Power Administration and is a preferred arrangement if bending moments are not required. The four gages are wired in a bridge, completion resistors are eliminated, and only one data channel is required per location. Each member is calibrated after the gages are applied and before assembly in the structure. Strain gage data on steel poles are taken in the same manner as single-channel data for lattice members, except that in-place calibration is not an option.

The four-channel axial and moment load data are most useful in showing changes in stress and stress distributions as a result of an applied tower load, whereas the single-channel axial configuration allows gaging of the maximum number of members.

A large number of structural data have been obtained during the 21 full-scale tests conducted at the TLMRF to date. The data have been valuable in defining the real capacity of structural members and in providing a measure of the difference between member loads predicted by current software and actual member loads. The testing has also pointed to some significant improvements that could be made in the TLMRF data acquisition and reduction system. During a given test, more members must be instrumented in order to fully define the true load distribution in the tower and max-

*TLWorkstation is an EPRI trademark.

imize the benefits of each full-scale test. The original TLMRF data system could reduce and display data for single channels (axial load only); experience has shown, however, that if member bending moments can be reduced and displayed, the failure load of the structure can be predicted at a point corresponding to 10–20% of the load total below the actual failure point.

A second control room computer has been added, and multiplex units transmit the data from an additional 128 channels to the control room. The added computer capability will permit on-line reduction of all data in engineering terms, continuous display of gaged member loads as a function of calculated member load capacity, and identification of tower failure load before reaching that load. This ability to predict member failure caused by buckling results from computation of bending moments in real time and forecasting what the moments will be at 100% structure loading. In addition, the improvements provide the capability to supply total test data (the most essential part of the test report) within a few hours of completing the full-scale test. Test-peculiar reduction software can be added to each test.

This improved TLMRF data acquisition/reduction system makes it possible to use full-scale testing as an integral part of the transmission structure design process because engineering data will be immediately available to the responsible designers. In addition, this system greatly improves the ability of the TLMRF researchers to understand the results of the EPRI full-scale research tests during the conduct of the test.

The expanded system was checked out during full-scale testing in December 1985 and is now in operation at TLMRF. An interim EPRI research report, which fully describes the TLMRF data system and the results of TLMRF full-scale testing from August 1983 through July 1985, will be available shortly. *Project Manager: Paul Lyons*

UNDERGROUND TRANSMISSION

Evaluation of materials for dc cable insulation

The property requirements for materials employed as electrical insulation for dc cables differ from those for ac cable insulation. In the latter case, the electric field is capacitively graded, whereas for dc cables, the electric field is resistively graded. Hence, the manner in which the insulation responds to the electric field is different. This leads to widely different responses to temperature changes, as resistivity of insulation is temperature dependent (inversely proportional), whereas capacitance is essentially temperature independent. In addition, the localized band region of maximum voltage stress differs for ac and dc fields. The maximum stress site in dc cable insulation is near the insulation shield; for ac cable, it is near the conductor shield. These differences must be considered for cable design.

When space charge is present, the stress distribution is modified even further, and breakdown of dc cable insulation may occur under conditions that would not induce breakdown of ac cable insulation. Rapid dissipation of space charge in dc cables is therefore desirable and necessary.

One approach to developing a reliable extruded insulation for dc cable is to incorporate a charged polymeric component into the insulation. Some studies have been performed where polyethylene insulation has been blended with an ionomer (charged polymer) to diminish space charge effects. The reasoning here is that contact electrification may be an indication of the propensity toward space charge buildup. When a material, such as polyethylene, with a negative contact electrification is blended with an ionomer (which has a positive contact electrification), the blend can have a contact electrification closer to zero than either component of the blend. This approach could produce insulation having good dc and impulse breakdown strengths.

Contact electrification is a phenomenon that arises when certain insulating materials are rubbed against each other; attraction and repulsion between objects charged in this manner are discussed in basic physics textbooks.

This general approach suggests an avenue for the potential development of materials suitable for dc cable insulation. Ionomer or perhaps other charged system blends may suitably facilitate dissipation of space charge; however, other aspects of blending polymeric ionic materials must also be considered in evaluating this situation—for example, compatibility, migration under voltage stress, aging effects.

To test this approach to the development of a reliable extruded dc insulation, a project has been initiated at the University of Connecticut to prepare and test polyethylene-ionomer blends (RP7897-9). The objectives are to determine the influence of ionomeric or other charged polymers on space charge diminution in blends with polyolefinic insulation in order to ascertain whether the mechanism involves contact electrification, and to determine whether aging under accelerated multiple stress conditions influences physical and electrical properties of the modified material. Analyses will be performed with techniques that include the following.

- Thermally stimulated currents to locate and identify trapping sites

- Contact electrification and electrometer probe measurements of the resulting surface potentials to characterize the tendency of each material to acquire surface charges

- Examination by scanning and electron microscope and electron spectroscopy by chemical analysis to study ion migration

- Microscopic examination of the aged film to locate any obvious defects

- Measurement of such electrical and physical properties as dielectric constant, dielectric loss, and elongation, along with changes that occur with aging

A related project at the National Bureau of Standards uses a thermal pulse method to study thin films of the same blends in an effort to understand charge dissipation (RP7897-11). *Project Manager: Bruce Bernstein*

TRANSMISSION SUBSTATIONS

Digital control and protection for transmission substations

At present, the control of a typical transmission substation involves a set of stand-alone systems or devices. Although this scheme is perfectly acceptable, it leads to unnecessary and costly redundancy because of duplication in wiring and functions. A digital system, built to meet all the functional requirements for control and protection of a substation, would probably provide significant benefits to the industry in terms of reduced cost per function. Such a system is being developed for transmission substation applications (RP1359). The chosen development strategy is a top-down approach, emphasizing the development of a system as opposed to stand-alone function units. The following criteria were established for the system.

- The critical protective relaying functions must operate even if the substation computer fails.

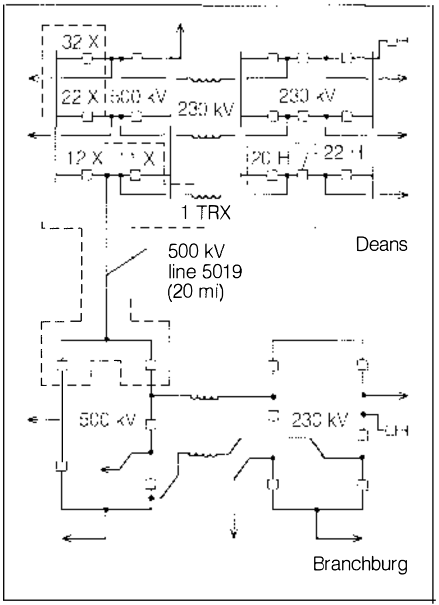
- Given redundancy, the system must perform all critical processing even if there is a single component failure anywhere in the system.

- The system must not require more than one fully redundant data acquisition subsystem to do the above.

- Large-scale integration technology should be used wherever possible.

Obviously, a radical departure from present designs must be carefully tested to gain user acceptance. Under EPRI sponsorship, Westinghouse Electric Corp. built a prototype system with matching stand-alone line-protection relaying terminals. In parallel, EPRI is also sponsoring the development of a second set of

Figure 1 Diagram showing the scope of the demonstration control and protection system at Deans and Branchburg substations, which are major switching points in the transmission system.



line-protective relaying devices under a contract with General Electric Co. Public Service Electric & Gas Co., of New Jersey, will install the equipment in an existing substation to gain operating experience.

Figure 1 shows a simplified one-line diagram for the two demonstration sites, the Deans and Branchburg substations. Both substations are 500/230-kV facilities and are major switching points in the transmission system. The dotted line defines the part of the system that will be controlled and protected by the newly developed digital control and protection system.

At Branchburg, a redundant set of digital pilot relays will protect line 5019. Each will work with digital pilot line relays installed at Deans. Also at Deans, digital protection will be provided to cover one 500-kV bus and one 500/230-kV transformer.

The areas that will be observed in the course of the demonstration of the integrated system are operating experience, user acceptance, and flexibility for modifications. The field demonstration is divided into four phases: field acceptance tests, open-loop demonstrations, staged fault tests, and programmed phase-in to operation.

The integrated equipment will be function-tested on a periodic basis. Additional functions or modifications to existing functions will be considered, both to enhance the system and to augment flexibility.

The concepts of integrated protection and control and the hardware configurations to achieve them have been discussed in previous status reports. The specific configuration selected for Deans is shown in Figure 2. The Deans system consists of a station computer at the top of the hierarchy, four protection clusters (PCs) arranged so that separation of protection zones is maintained, and seven data acquisition units (DAUs). Two line-protection units of different design are part of the system. Each of the DAUs is connected to one or more PCs. Two of the DAUs are located in the switchyard and use fiber-optic cables for signal transmission. The rest of the equipment is located inside the control house.

The interfaces, which interconnect the modules of the system, are also known. They consist of the data highway, which connects the station computer to the PCs; the data links, which connect the PCs to the DAUs, and the external interfaces. These provide communication with a substation control and data acquisition (SCADA) master, a protection engineer's console located at the utility's offices, and a remote printer for logging sequence-of-event messages at the same office.

This project is approaching its conclusion. The Branchburg line relaying systems were delivered in 1984 and put into open-loop demonstration. The Deans system is expected to be installed in mid 1986, with the redundant line-protective relaying units to be integrated into the system in 1987. Fifteen additional line-protection systems will be built for trial operation in 1986 and 1987. *Project Manager: Stig L. Nilsson*

Amorphous metal core power transformers

The magnetic and electrical properties of a family of iron alloys (Metglas) developed by Allied Corp. hold the promise of reducing no-load losses in transformer cores to one-third the level achieved by the best conventional steels. These liquids are unique in that they can be solidified so rapidly that an orderly crystalline atomic structure does not form. Instead, the alloy, like glass, has an amorphous arrangement of atoms. The thinness, high resistivity, and noncrystalline nature of the material leads to low eddy-current and hysteresis losses. A series of projects was undertaken in 1978 with Allied and Westinghouse to verify that reduced losses can be obtained at a reasonable cost (RP1290-1–4 and RP2236-1 and -2).

Earlier work at Allied concentrated on identifying the preferred alloy or alloys and then developing a continuous casting operation with the necessary automatic features to stringently control the dimensions of the amorphous metal ribbon. Parallel work at Westinghouse studied the suitability of the material for transformer applications and investigated methods that could be used to build a power transformer core from the new material.

A 500-kVA three-phase transformer with an

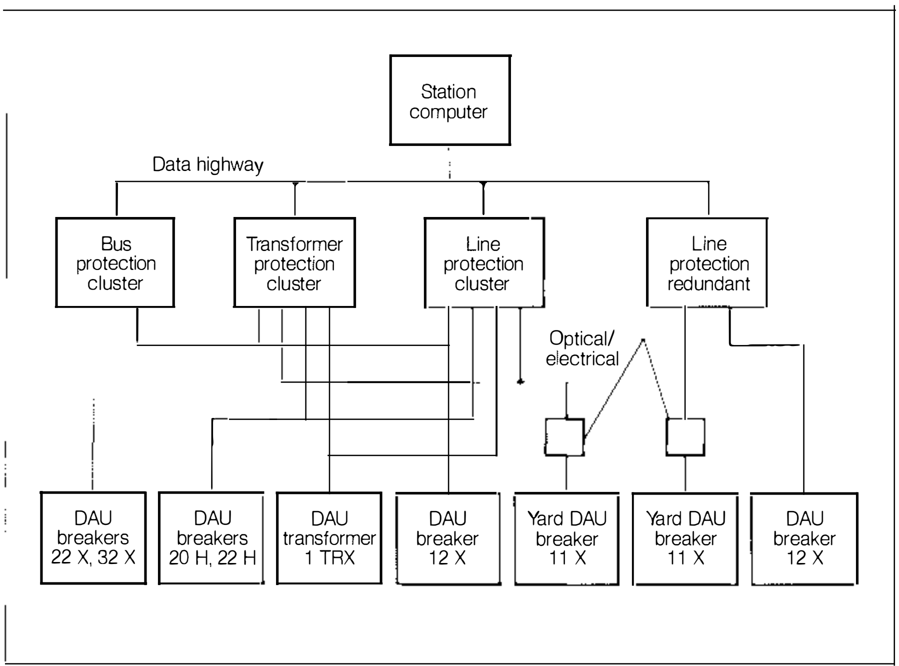


Figure 2 Deans substation system configuration. Separate protection clusters and seven data acquisition units maintain mutually exclusive protection zones. The station computer interfaces with the protection clusters that separate the zones.

amorphous core was built for a five-year field trial but failed during factory tests because of a turn-to-turn flashover. The unit was disassembled, carefully examined, and tested in an effort to ascertain the cause of the failure. No conclusions were reached, but from the location of the arcing and the fact that mass spectrographic analysis of samples disclosed a complete lack of core material at that site, it was clear that the amorphous metal core was not involved. On the basis of this information, project researchers decided to repair the windings and to continue with the program. The rebuilt unit successfully passed all factory electrical tests and is about to be installed on the Niagara Mohawk Power Corp. system for field operation.

Attention now focuses on producing cold-welded laminate approximately 0.25 mm thick from several layers of thin ribbon. Allied has purchased, refurbished, and installed a used rolling mill for producing this laminated material, which it calls Powercore. Powercore has slightly higher losses than does single-layer thin ribbon, and there is a cost associated with the consolidation process. Its increased thickness and improved space factor are of advantage to the transformer manufacturer, however, and make this the most likely candidate for first commercialization of a power transformer with an amorphous metal core. Work is proceeding to determine ways to maximize the throughput of the rolling mill but retain strict dimensional control.

Alternative core construction techniques that use moderate-scale corelets are being studied. Key issues are space factor, labor costs, and electrical losses. Westinghouse has developed appropriate methods for cutting the amorphous metal ribbon. A preliminary plan is to use automatic equipment to cut and stack the material for power transformer cores. Installation of such a pilot line will be the next major goal. *Project Manager: B. L. Damsky*

PLANT ELECTRICAL SYSTEMS AND EQUIPMENT

Optimal efficiency of induction motors

The size and cost of induction motors have been falling steadily and dramatically over the years, and as a natural consequence, motor efficiency has also trended down. This has not been of great concern to motor users until fairly recently, when the increasing cost of energy focused attention on efficiency. Because 9% of all power generated in the United States is fed to power plant motors, even a modest improvement in motor efficiency can be a very worthwhile objective for today's utilities.

Manufacturers have improved motor efficiency by adding active material and increasing frame size. However, the true key to improving efficiency lies in optimizing the motor design in the first place, with the highest possible efficiency, instead of the lowest cost, as the design objective. A project initiated in 1981 has been directed toward the development of such optimization techniques (RP1944). It has also involved a search for other methods of drive system efficiency improvement.

The first and most fundamental effort was directed toward three-phase motor design. This work is now complete, and the final report has been published (EL-4152-CCM, *Optimization of Induction Motor Efficiency;* Vol. 1: *Three-Phase Induction Motors*). A computer program also is available to motor designers to assist them in applying the technique. An extension of this method to the design of single-phase motors is currently in progress, and the results should be published by mid 1986.

Another approach to motor efficiency optimization was proposed by C. L. Wanlass in 1978, which claims substantial energy savings when three-phase induction motors are connected in a particular way (the Wanlass connection, U.S. Pat. 4063155). A rewinding and reconnecting service based on this patent is being offered in the marketplace. Comprehensive tests to evaluate this method were undertaken as part of RP1944. Using recently calibrated instruments, the project team first tested a 15-hp motor rewound by a professional repair shop. The motor was wound so it could be tested in both the Wanlass and the standard modes without changing the instrumentation or windings in any way. The team later conducted similar tests on a 5-hp motor and on a different 15-hp motor provided by the Wanlass Corp. Wanlass representatives participated in all phases of the testing program.

On the basis of all the tests performed on these three motors at the University of Colorado, researchers found no reason to conclude that a motor connected in the Wanlass mode has a higher efficiency than the same motor connected in the standard mode. The final report on this testing and comparison has been published in EL-4152, *Optimization of Induction Motor Efficiency;* Vol. 3: *Experimental Comparison of Standard Motors With Wanlass Motors.* *Project Manager: J C. White*

Assessment of motor-generator insulation

The reliability of all electrical equipment is controlled primarily by the insulation employed; electrical insulation can be viewed as the material that separates, isolates, and protects one conducting material from another. How well the insulation serves in that role will depend on the way it is applied to the conductor and the way it responds to service-induced stress. All insulation is exposed to multiple stresses caused by electrical, mechanical, and thermal service conditions and by exposure to the local environment. The magnitude of these individual components will vary, however, according to the kind of electrical equipment employed (e.g., motors, generators, cables, transformers). Hence, various types of insulation, mostly polymeric, are employed for various applications.

In the case of rotating electrical machinery, the stresses are significant in all the above areas; voltage stress impinging on the windings of motors and generators can contribute to severe thermal and mechanical stresses. These in turn can lead to partial degradation of the insulation, which can cause formation of voids, within which discharges (induced by the voltage stress) can then occur.

A primary goal of engineers concerned with reliable operation of equipment is to be able to predict equipment lifetime, which is in essence a function of the reliability of the insulation system. This is an important objective but is extremely difficult (though not impossible) to achieve in practice. EPRI has entered into a four-year project with Ontario Hydro to seek practical methods by which utility engineers can achieve this objective (RP2577).

The integrity of the insulation in a rotating electrical machine is critical to its proper operation. For example, failure of the stator winding insulation, or progressive breakdown of the rotor insulation, will force a machine outage and may result in extensive winding and iron damage. Although catastrophic insulation failures are infrequent, they are not uncommon and represent a costly repair item for large generators, particularly in terms of replacement power costs. Development of methods and tools to prevent such failures is of high interest.

The objective of this new project is to develop superior procedures for assessing the condition of aged insulation in rotating electrical machinery and to use the new techniques and information obtained to develop more-reliable methods for estimating the remaining life of such insulation in power plant motors and generators. A further objective is to demonstrate the validity of the test method(s). Another objective is to commercialize any new test equipment developed for this purpose.

In the past Ontario Hydro pioneered the application of partial discharge measurement techniques to facilitate such diagnoses. This new project will extend the technology and explore newer diagnostic methods. In addition, a subcontractor, Foster Miller, Inc., will seek to determine the specific site of localized partial discharges. *Project Manager: Bruce Bernstein*

R&D Status Report
ENERGY ANALYSIS AND ENVIRONMENT DIVISION

René Malès, Vice President

INSTREAM FLOW METHODOLOGIES

The amount of water that can be taken from a stream for power generation while maintaining biologic and esthetic stream resources is one of the most important determinants of water supply availability and economic feasibility for hydroelectric developments. For projects that divert water out of the stream bed by using flow lines and penstocks, the instream flow requirement is the volume of water that must be left in the stream to serve biologic and esthetic functions. For projects that do not bypass the stream bed, instream flow requirements specify minimum flows that must be released (through or around the hydroelectric turbine) and may also specify the rate of change of flows and maximum allowable flows. Instream flow requirements tend to cause such nondiverting projects to be operated in a run-of-river mode rather than a peaking mode. There are many methods in use for determining instream flow requirements, but most are unpublished or poorly documented, and very few have been tested for reliability or for their ability to predict biologic effects. To make more methods available to utilities, EPRI has compiled, summarized, and critically reviewed over 50 of them in RP2194-2. The contractor is EA Engineering, Science, and Technology, Inc.

Methods for determining appropriate instream flows fall into two fairly distinct categories: those that are essentially policy statements and those that establish a site-specific functional relationship between instream flow and some measure of habitat quality. The policy methods are all based on assumed linear relationships between one or more readily measured physical variables and the recommended instream flow. Typical policy-type formulations for minimum releases are as follows: (4 ft^3/s)/mi^2 of drainage basin area; 30% of the unregulated mean annual discharge; the flow equaled or exceeded 50% of the time; and the lowest flow occurring for seven consecutive days in a 10-year period. Most of these policy statements were developed intuitively, and when applied to the same stream, they can result in widely divergent flow recommendations.

The alternative methods, which use local measures of habitat quality that change with flow, are all nonlinear and generally have as their endpoint not a specific flow recommendation but a curve relating habitat quality to flow. Thus the decision of the appropriate flow is external to the method. Typical decisions, however, are based on formulations of the minimum acceptable flow, such as the flow resulting in the highest-quality habitat; the flow resulting in the habitat quality that is equaled or exceeded 50% of the time under unregulated conditions; or, more vaguely, the flow at which there is a break point in the curve relating habitat to flow (in effect, the point at which the curve's interpreter senses diminishing returns in terms of habitat as flows are increased).

In RP2194-2 the contractor has examined the existing instream flow and habitat quality methods to identify their assumptions, to characterize the type and strength of the data on which they are based, and to review studies testing their ability to predict or reflect biologic responses to altered flows. The initial stage of the project consisted of collecting and reviewing all available documentation for the methods. Most of this documentation, particularly that for testing, is not in the refereed technical literature but rather in unpublished theses, internal state and federal agency contract completion reports, volumes of papers compiled from workshops and symposia, and short publications produced by state and federal agencies.

To make the documentation more accessible, the contractor has produced a one-page methodology summary form for each of some 50 techniques; this form identifies the input and response variables, describes the approach used, cites and summarizes any validation studies, and presents a critical review of the method. In addition, the contractor has prepared a detailed overview that discusses all aspects of instream flow modeling and reviews all available tests of the various methods; this will be published as an EPRI report.

Interim results

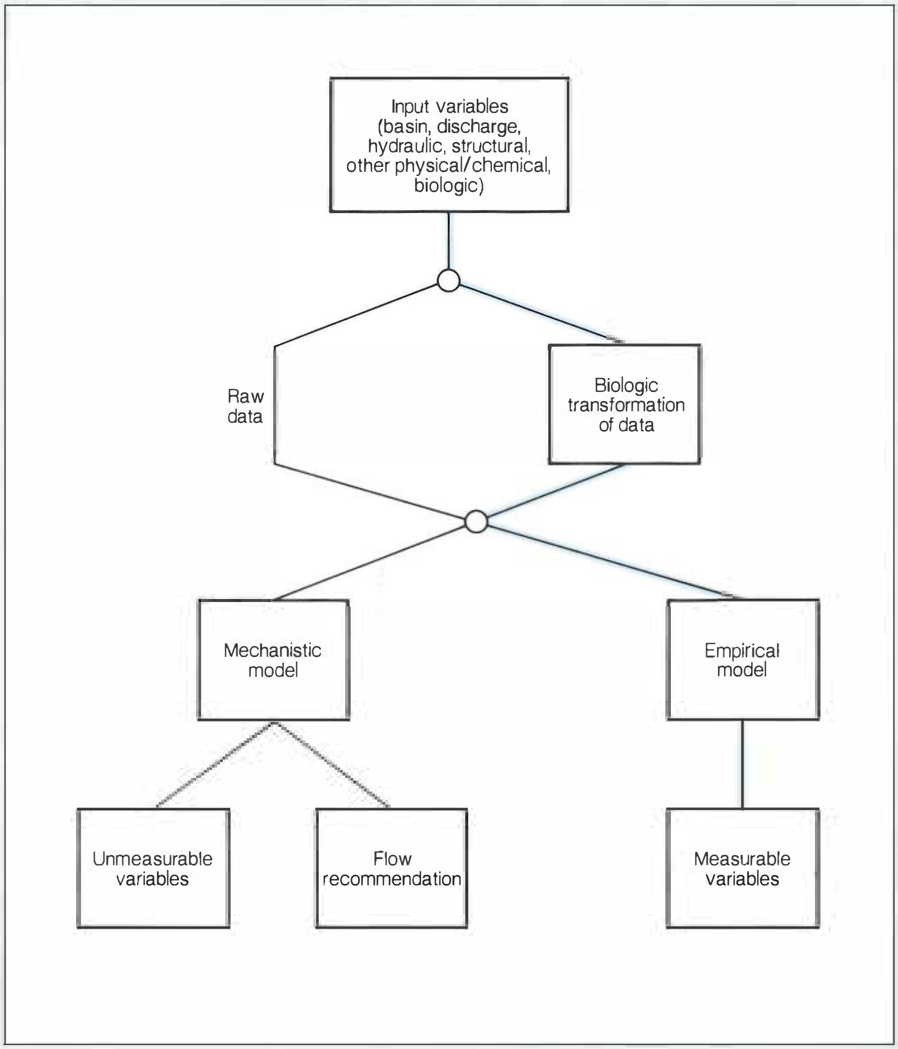
During the course of these reviews, it became apparent that few of the techniques currently in use have been appropriately tested for validity and predictive ability. The results show a low or erratic level of predictive ability or one that is strongly geographically constrained. Both the lack of testing and the poor method performance are due principally to the complexity of stream ecosystems. It is difficult to design, and expensive to conduct, a study that will conclusively demonstrate the biologic impact of altering stream flow. And, even with good results from one stream in hand, it is likely that other considerations will apply for another stream, particularly one some distance away or in different terrain.

Most of the modeling to date has been mechanistic in the sense that modelers have assumed very simple mechanisms and have applied models without checking their output against biologic responses. The most prevalent assumption is that fish populations are controlled by the depth and velocity of the water in streams. In some instances, the numerical values of depth, velocity, and other physical variables are transformed into indexes of biologic importance before being used in the model. (Although this practice can create problems if poorly implemented, it can also be a useful part of modeling.) In general, mechanistic models produce unmeasurable output variables. Correlations have been demonstrated between some of these output variables and actual biologic responses, but not repeatably and with very wide confidence intervals for predictions.

A small part of the modeling has been empirical, primarily involving multiple linear regressions of standing crop (of fish) on as many as 20 physical and biologic input variables. Again, in some cases, the input variables are transformed into indexes of biologic importance before they are used in the models. Some of the empirical models have turned out to be unreliable in predicting biologic response to changes in the very streams on which they were developed, indicating that the controlling variables were omitted from the analyses. Others have been shown to predict biologic characteristics reliably for their home streams but unreliably elsewhere; this suggests, as might be expected, geographic variation in factors that control biologic populations.

The results of RP2194-2 to date indicate that none of the instream flow or habitat quality models reviewed meets reasonable criteria for predicting biologic effects (although most have features that are expected to contribute to a successful model). Consequently, instream flow recommendations based on existing models should not be assumed to correspond to the flows needed to ensure the integrity of aquatic ecosystems.

Figure 1 Mechanistic versus empirical instream flow modeling. (The circles indicate decision points.) Many existing methods feature mechanistic models that use basin or discharge input variables to produce unmeasurable output variables. EPRI is taking an empirical modeling approach (color) that emphasizes the use of local habitat variables to predict measurable biologic effects. Both model types can use either raw data or data that have been transformed into an index of biologic importance.



Ongoing efforts

Virtually all the testing of existing methods has focused on unregulated and undiverted streams. Given that the purpose of most methods is to determine what flows are appropriate after regulation or diversion, it is surprising that they have not been intensively tested on streams already affected by projects.

The continuing studies under RP2194-2 are directed both at evaluating the reliability of existing methods for regulated and diverted streams and at developing new methods that will be predictive of project-induced effects. The researchers will determine, for several streams with long-term diversions, whether any of the existing methods would have predicted the biologic outcome of diversion, and will apply the techniques of empirical descriptive statistical modeling to these same streams to construct a model that can predict the effects of diversion. Both studies are intended to illustrate alternative and better approaches to dealing with instream issues.

The first study seeks to focus attention on the real issue: whether or not habitat as characterized in existing methods is in fact limiting to fish populations. Data collected by the contractor for a series of streams with long-term hydroelectric projects strongly suggest that the effects of diversion on fish populations have not been as great as most instream flow methods would indicate.

The second study will provide an example of an empirical, as opposed to a mechanistic, approach to instream flow determination (Figure 1). Because empirical descriptive methods have been the most successful methods for free-flowing streams, it is possible that they will be successful for altered streams.

In another part of the ongoing work, EPRI is sponsoring seminars to present the information gathered to date to the user community. The first seminar was held in Washington, D.C., this past February, and the second will be held in Seattle on July 16, 1986. *Project Manager: Edward Altouney*

PCB ECONOMIC RISK MANAGEMENT

In a desire to limit health and ecological risks, federal, state, and local agencies have regulated the use of electrical equipment containing high levels of PCBs (often referred to as askarel equipment). Utilities continue to have discretion, however, on the use of askarel transformers and capacitors in nonpublic locations, such as power plants and substations. They also have discretion over the continued use of mineral-oil-filled equipment that *may be contaminated with small amounts of PCBs. Although this discretionary equipment may pose only a minimal health risk, it may pose a serious economic risk to a utility in the case of a major leak or fire. Such incidents are rare, but the potential economic costs are very large. And the likelihood, severity, and cost of an incident are all highly uncertain. As a consequence, risk management decisions concerning PCB equipment are a difficult challenge for utility managers.*

To address this challenge, EPRI has developed two decision support tools that can help utility personnel manage the economic risks associated with PCB equipment (RP2595). ASK, a PCB economic risk management model, and COIL, a contaminated-oil economic risk management model, are based on the methodology of decision analysis. ASK focuses on the question of when to replace PCB equipment; COIL focuses on whether sampling to determine if mineral-oil-filled equipment is contaminated by PCBs is worth the cost.

Developed for EPRI by Decision Focus, Inc., ASK and COIL provide techniques for comparing the costs and benefits of alternative equipment management strategies. The two models focus on economic risks, which include direct equipment and cleanup costs as well as costs that may be incurred because of real or perceived health or ecological effects from releases of PCBs. Health and environmental risks are addressed directly in other EPRI models. For example, the TRIM (transformer/capacitor risk management) model has been developed for the cost-benefit analysis of alternative regulatory proposals for dealing with PCB equipment (*EPRI Journal*, January/February 1985, p. 56).

Management alternatives

Utilities have a variety of options for managing the economic risks associated with equipment that contains PCBs. Possible measures include replacing existing equipment with one or more alternative types of equipment, isolating the equipment or installing electrical protection devices to reduce risks, retrofilling the equipment to reduce PCB levels, or retaining the existing equipment as is. Replacement may involve significant costs for a new unit and its installation, but it may improve the operating efficiency and will eliminate the possibility of a PCB incident. Incidents involving substitute equipment may occur with greater frequency and with greater risk of conventional damage, but they are unlikely to lead to the larger costs sometimes associated with PCB incidents.

For mineral-oil-filled equipment, testing before any incident occurs can indicate the level of PCB contamination present. Testing that establishes in advance that contamination is extremely low may help a utility avoid the excessive costs associated with public perceptions of an incident involving PCBs. If the likelihood of severe contamination is low and incidents are rare, however, the cost of equipment testing may exceed the value of information gained.

With or without testing, utilities must select a management strategy for potentially contaminated equipment as well as for equipment with known PCB content. Choosing the best management strategy requires careful weighing of uncertain losses against known cost and performance considerations. Is an investment in risk reduction measures or new equipment merited to remove the possibility of a potentially very expensive but relatively unlikely incident? Management questions such as this are difficult because of the large uncertainties in the likelihood, severity, and cost of incidents, as well as the complexity of cost, performance, and financial considerations.

Aids to decision making

ASK and COIL are decision support tools designed to help utility personnel analyze management alternatives. Both ASK and COIL incorporate equipment cost and performance calculations, financial calculations to account for costs to ratepayers and owners, and explicit representations of uncertainties in the occurrence, severity, and cost of incidents. These features are combined in interactive software packages that implement the two decision support tools in the form of computer models. The models can be described in terms of decision trees and submodels that calculate the implications of each path through the decision trees.

The decision tree for ASK is used to calculate expected costs and the range of uncertainty over a large number of scenarios. These scenarios comprise combinations of specific management decisions and possible outcomes of uncertain variables affecting the implications of those decisions. The equipment management alternatives are defined at the first node of the tree, which is followed by a series of nodes that represent the uncertainties—incident frequency, type of incident, cleanup costs, plant shutdown costs, and liability costs. The decision tree for COIL is similar but includes an explicit representation of the sample/no sample choice before the equipment management alternative choice.

For each scenario defined by a tree, the calculations in ASK and COIL are carried out by using the submodels shown in Figure 2. The equipment submodel calculates all costs associated with existing and replacement equipment. It can take into account different operating and maintenance costs and efficiencies for different types of equipment. The incident occurrence submodel calculates the likelihood, potential timing, and likely severity of an

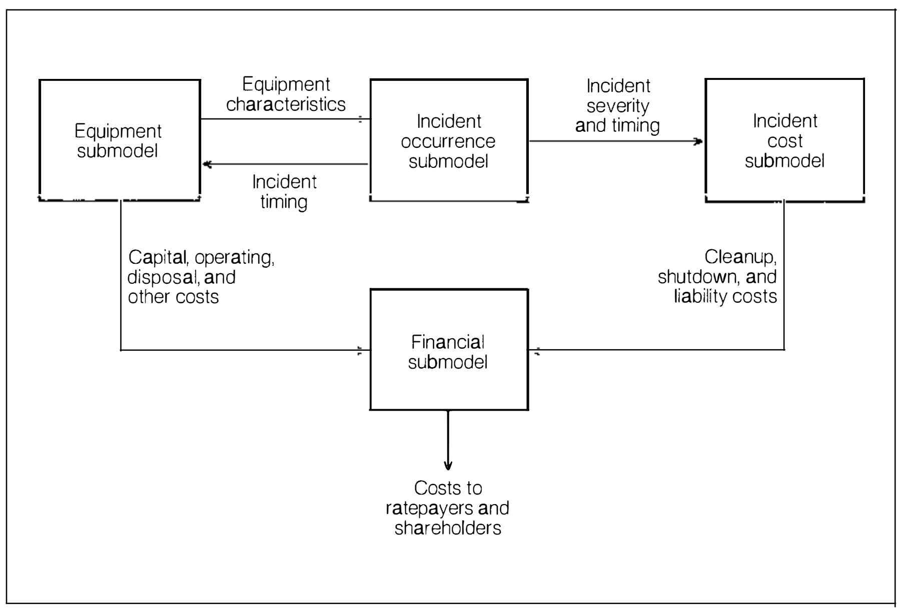


Figure 2 ASK and COIL use this set of submodels to calculate the costs of alternative management strategies for PCB and contaminated-oil-filled equipment. EPRI has developed these two decision support tools to help utility personnel manage the economic risks associated with this equipment.

incident, using values for the uncertain parameters identified in the decision tree.

The incident cost submodel calculates all the costs of an incident, given that one occurs. These can include cleanup and repair costs, costs of legal liabilities, and costs due to the shutdown of a generating plant during the cleanup and repair period. The financial submodel incorporates utility cost-of-service calculations, distinguishes between capitalized and expensed costs, calculates the operating efficiency of alternative types of equipment, and calculates costs to both ratepayers and owners.

Application of ASK

ASK was recently applied to an analysis of PCB risk management options at a 600-MW generating station. The plant had 82 askarel transformer-rectifier (TR) sets in its electrostatic precipitators. The issue facing the utility's management was whether to eliminate the possibility of accidents involving PCBs by replacing the existing askarel TR sets. The analysis was carried out for a single typical unit, and conclusions for the single unit were then extrapolated to the entire set of 82 units.

Replacement would incur immediate expenses for the purchase and installation of the new equipment and the disposal of the old unit. In this analysis it was assumed that there would be no costly incidents with the replacement equipment. The total life-cycle cost to the ratepayer of the replacement option, including the yet-to-be-recovered revenue requirements of the equipment that was replaced, was calculated by ASK to have a present value of about $33,000.

Estimating the expected total life-cycle cost of retaining the existing equipment was more difficult because it included the expected costs of an incident (which are defined as the costs of an incident, if it occurs, times the probability of the incident's occurrence). The incident cost components included cleanup costs, replacement power costs that would be incurred if the plant shut down during cleanup, and liability expenses plus legal fees. The expected costs for these components were estimated for three types of incident: a large spill, smoke without a fire, and a large fire.

Table 1
COSTS OF EQUIPMENT MANAGEMENT OPTIONS
(1985 $)

Cost Component	Replace Equipment	Retain Equipment
Equipment	33,020	17,680*
Cleanup†	0	488
Replacement power during plant shutdown†	0	772
Liability and legal services†	0	4,599
Total	33,020	23,539

*This includes the yet-to-be recovered revenue requirements of the existing equipment plus the discounted cost of the equipment's replacement at the end of its useful life.

†Expected value (i.e., cost times the probability of an incident).

Because incident costs are uncertain, they were entered into ASK as ranges of values with probabilities associated with each value in the range. The values were contingent on the type of incident. For example, for a large fire, the utility's management estimated that there was a 50% chance that liability costs would be about $7 million, a 30% chance they would be about $27 million, and a 20% chance they would be about $60 million. Similar distributions were estimated for cleanup costs and replacement power costs for each type of incident.

The expected total life-cycle cost of the equipment retention option was estimated by ASK to be about $23,500 per TR set. This is approximately $9500 less than the life-cycle cost of the replacement option. For the 82 TR sets, the total expected savings from the retention option is about $780,000.

The breakdown of the cost components is shown in Table 1. The higher equipment costs of the replacement option more than outweigh that option's zero cleanup, replacement power, and liability costs. The table shows that the largest incident cost component, liability, could be twice as high and yet not change the rankings. It is also clear that assumptions about cleanup costs and replacement power costs would have to change significantly in order to change the ranking of options.

Because ASK was easy to run, the analysts were able to evaluate a number of sensitivity cases quickly to verify the insights presented above. These cases showed that it was difficult to envision a scenario in which the replacement option was superior. It is important to note, however, that these results are for a particular power plant; results may differ dramatically from plant to plant.

Model benefits

ASK and COIL allow utility personnel to evaluate PCB equipment management options for a wide range of situations. Comprehensive analyses can be carried out quickly and efficiently to compare different management options in terms of the direct costs and the costs of incidents. Uncertainties in incident occurrence, severity, and cost can be accounted for explicitly, and a wide variety of "what if" questions can be answered rapidly.

In addition to serving as useful aids in analysis, ASK and COIL can help utility personnel communicate with top management, regulators, and public groups about the complex nature of PCB and contaminated-mineral-oil problems. The tables produced by ASK and COIL show both the assumptions and the results clearly. The implications of alternative viewpoints and opinions can be tested and displayed quickly and easily, thus facilitating discussion and consensus building on difficult PCB management issues.

ASK and COIL are available for use on an IBM PC or a compatible personal computer. The software is available from EPRI's Electric Power Software Center. A draft report describing ASK and COIL is available from EPRI. *Project Manager: Victor Niemeyer*

R&D Status Report
ENERGY MANAGEMENT AND UTILIZATION DIVISION

Fritz Kalhammer, Vice President

COMPRESSED–AIR ENERGY STORAGE

*EPRI's compressed-air energy storage (CAES) R&D has been aimed primarily at improving the prospects for the commercial success of CAES plants. Over the past year and a half, since the last status report on CAES (*EPRI Journal*, October 1984, p. 55), the work has substantially reduced the risk to early buyers of CAES plants by decreasing plant size, enhancing the durability of the exhaust stack recuperator, and improving our understanding of the geochemistry of aquifer air storage systems. Further, the commercial viability of CAES has been enhanced by these international developments: the continuing record of highly reliable operation at the 290-MW Huntorf plant, commitments to build a 1050-MW plant in the Soviet Union, and plans for the operation (this year) of a 25-MW Italian plant. The first U.S. CAES plant is expected to be a 50-MW system that Alabama Electric Cooperative, Inc., plans to have on-line in 1989. Other utilities with plans to build plants soon thereafter are Southern California Edison Co. (SCE), Sacramento Municipal Utility District, and Cleveland Electric Illuminating Co.*

The increasing cost of supplying electricity for peak and intermediate duty has prompted the need for energy storage technologies. These technologies use relatively inexpensive off-peak energy from coal- or nuclear-powered baseload units to produce electricity later to meet peak and intermediate demand. Currently, the only method of energy storage available to U.S. utilities is pumped hydroelectric. Pumped-hydro facilities supply less than 1% of all U.S. electric energy—about one-fifth of the potential for energy storage. Because of the large plant size required (over 500 MW), the long lead time, and regulatory constraints, pumped hydro does not meet the industry's strategic need for a modular power system with a short lead time. Although pumped hydro is a viable resource, U.S. utilities clearly need a storage alternative that is more suitable for helping them face uncertain load and regulatory requirements.

Proven, highly reliable, and cost-effective, CAES is modular and viable energy management option for utility application. For each kWh of plant output, it uses 0.75 kWh of electricity and 4000 Btu of oil or gas fuel. The electricity, obtained off-peak from coal or nuclear baseload plants, is used to compress air, which is stored in underground caverns (rock or salt) or aquifer reservoirs. During times of peak or intermediate electricity demand, the air is released and heated to drive an expansion turbine connected to an electric generator. Virtually all the component equipment used in such a plant is now available off the shelf, with standard warranties.

In conventional combustion turbine plants, about two-thirds of the turbine's power goes toward driving a compressor. By relieving the turbine of this burden, CAES plants produce three times as much power from a Btu of oil or gas as conventional combustion turbines. Emissions from a CAES plant, for the same reason, are one-third those of a combustion turbine per unit of electricity generation.

Mini-CAES

Information on a CAES plant that is smaller than the standard 220-MW size, the so-called mini-CAES plant, is available from an EPRI-funded study (EM-3855). The objective of the study was to estimate the cost and performance characteristics of mini-CAES plants that use existing equipment. During the course of the study, the vendors demonstrated not only that they could supply all the components but also that they are willing, as they are for larger plants, to provide warranties.

The study results indicate that mini-CAES plants are competitive with larger plants in performance and in cost (Table 1). Further, they can be built in significantly less time because they are skid mounted and require much less

Table 1
CAES PLANT COSTS
(January 1984 $/kW)

	Power Rating (10-h storage)			
	25 MW	50 MW	100 MW	220 MW
Aquifer geology				
Plant cost	614	477	465	572
Marginal cost	0.2	0.2	0.2	0.2
Salt geology				
Plant cost	664	495	471	579
Marginal cost	6	5	5	2
Rock geology				
Plant cost	1166	847	750	618
Marginal cost	39	31	31	6

Note: Plant costs cover all above- and below-ground costs except for interest and escalation during construction (2½ yr for the three smaller plants and 4½ yr for the 220-MW plant). The costs assume first-of-a-kind machinery in the 220-MW plant and existing machinery in the smaller plants. The marginal cost is the cost for one additional hour of storage above 10 h.

field labor during construction. The modularity of mini-CAES plants also allows a utility to build them as needed; and because the equipment they use is available from many more manufacturers than is the equipment for larger plants, the selection of compressors and turbines can conform much more closely to the optimized values determined by thermodynamic, geologic, and load shape requirements. As a result, smaller plants can offer utilities a more attractive specific cost ($/kW) and much more attractive financial benefits.

Recuperator corrosion

An optimized CAES cycle requires a recuperator to recover exhaust heat from the expansion turbine and to use it to preheat the combustion air withdrawn from storage. Using a recuperator reduces the plant heat rate from 5500 to 4000 Btu/kWh, a 27% improvement. For a 220-MW plant operating 2000 h/yr in the generating mode, a recuperator will reduce fuel expenditures by approximately $3 million a year (assuming a fuel cost of $4.50/10^6 Btu). This saving will pay back the recuperator capital cost in less than one year.

Cold-end corrosion caused by sulfuric acid is a problem in boilers and turbine exhaust gas waste heat boilers. Normally, operating conditions can be changed to reduce or eliminate condensing-acid corrosion, but in a CAES plant this approach is not practical. This concern, as well as cyclic fatigue stress in a CAES recuperator, is documented in EM-3843. To quantify corrosion effects, rig testing was performed under the exhaust gas conditions and metal temperatures of the low-temperature section of a proposed recuperator. The test section contained 14 tubes of different metals, and No. 2 fuel oil doped to a 1.2% sulfur content was used as the test fuel.

There were two steady-state tests—one at a metal temperature of 190°F (88°C) for 920 h and another at 130°F (54°C) for 2435 h—and one cyclic test at 190°F for 2100 h. Heavy corrosion deposits formed on all tubes in each test. These were loose enough that some spalling occurred in operation. The deposits appear to be hygroscopic and are water soluble; therefore, rinsing with water removed most of them. If deposits are not removed, it seems that in approximately the first 400 h of operation, the heat transfer rate would be halved.

Their high rate of formation requires that the deposits be removed on a periodic basis. However, there are indications that the deposits act as a corrosion barrier, in which case water washing may accelerate the corrosion process. Additional long-term testing is planned with weekly washing.

The corrosion tests suggest that a recuperator tube life of 20 yr can be achieved by using 0.065-in-thick (1.65-mm) Inconel 625, Inconel 825, or Carpenter 20Cb3 tubes and a fuel containing no more than 1.2% sulfur. Although this tube life is adequate for commercial application, EPRI is exploring design concepts to eliminate the condensation of sulfuric acid.

Champagne effect

The use of excavated rock caverns for storing compressed air has been extensively studied under RP1081-1 (*EPRI Journal,* December 1983, p. 61) It is preferable to keep this kind of cavern at constant pressure, in order to reduce the volume needed and the associated cost, rather than at a variable pressure (as in salt reservoirs). The constant pressure is maintained by means of a water compensation technique—that is, by a static head of water connecting the cavern to a small surface reservoir. Associated with this design approach, however, is the potential champagne effect: a transient flow problem caused by air dissolving into the high-pressure cavern water, coming out of solution and forming bubbles in the upper portion of the vertical water shaft, and increasing the water flow rate. An example of a champagne-effect transient is shown in Figure 1.

It has been postulated that bubble formation might be extreme enough to cause unacceptable flow transients during the charging process. However, a two-phase-flow computer simulation of the problem has shown that the bubble formation process and the damping forces associated with a specially designed U-bend in the piping will reduce the transients to acceptable levels (interim report for RP1791-2). Work is under way to confirm these computer simulation predictions. In RP2488-3 United Technologies Research Center is further developing the computer model, and in RP1791-13 Société Electrique de l'Our is acquiring field data for model calibration at an 18-bar (1.8-MPa) facility in Urschmitt, Federal Republic of Germany.

Preliminary field data confirm the model's general predictions for an 18-bar cavern pressure. It was necessary to adjust the model, however, to properly correlate its predictions with the field data. The field data showed that the mechanism for bubble development involves a time delay proportional to the vertical shaft water velocity, which in turn is proportional to the vertical shaft bubble volume. This creates a complex modeling problem, which was addressed by adjusting the model parameters for each velocity considered.

The use of this adjusted model under worst-case conditions (i.e., higher-pressure CAES environments) indicated that bubble formation is considerably slower than originally thought; thus CAES plants are safe with respect to the champagne effect if proper engineering is applied to the problem. In the top portion of the vertical shaft, however, for a period of about 10 min in a 10-h charging process of a full-scale plant, the water velocity approaches 3 m/s, the void fraction (the proportion of gas) approaches 50%, and the liquid-gas mixture is in the churn-flow turbulent region. These conditions will require the use of a steel lining in the

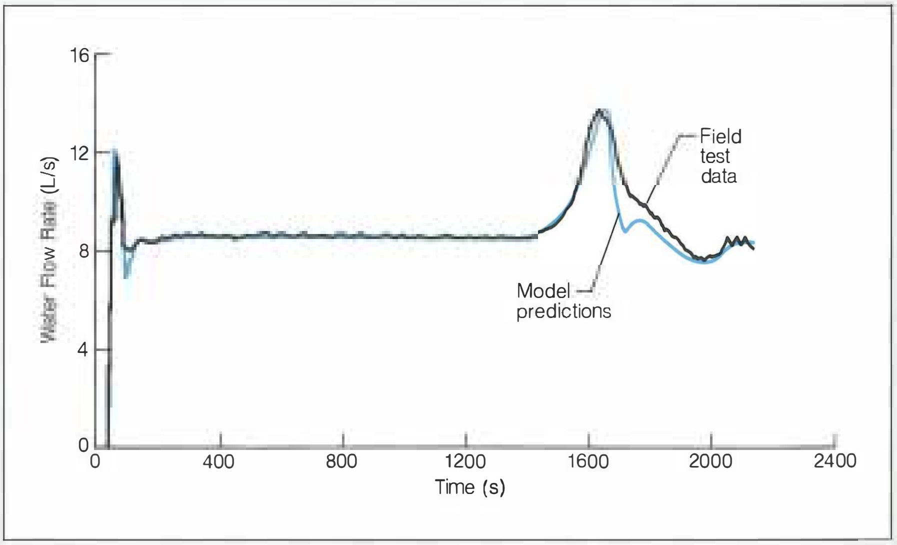


Figure 1 Data from an 18-bar field test of a champagne-effect transient are compared with computer model predictions. As air enters the cavern (from the plant air compressor), water leaves the cavern at the desired flow rate until bubbles evolving from the saturated water cause flow instability at 1600 s.

top 30–50 m of the vertical shaft to reduce shaft erosion to acceptable levels. It is expected that final reports for these projects will be published in late 1986.

Aquifer field test

The Pittsfield (Illinois) aquifer test was designed to demonstrate the feasibility of daily injection, storage, withdrawal, and subsequent cycling of compressed air in an aquifer reservoir. DOE, with Battelle, Pacific Northwest Laboratories as the contractor, provided funding for initial site selection, design, engineering, construction, and the development of an air bubble in the aquifer (January 1981–February 1983). Subsequently, the facility was turned over to and funded by EPRI. The test results have shown that air can be injected and withdrawn at this site much as gas is in natural gas storage fields (*EPRI Journal,* December 1983).

The testing has yielded one unexpected result: the depletion of oxygen from the stored air was observed during an extended dormant period with no air cycling. During the daily injection and withdrawal cycles, the oxygen level had been the same as that of the incoming ambient air. However, oxygen measurements indicated that 5 or 6 mo into the dormant period, the oxygen content started to decrease from the nominal value of 21%; after about 12 mo with no air cycling, it had decreased to 6%. The reasons for this loss of oxygen are being investigated by core analysis, air and water sampling, and laboratory studies. Possible mechanisms include biologic and geochemical reactions, as well as oxygen absorption into anaerobic water or adsorption onto rock particles.

For most CAES applications based on a daily charge-discharge cycle, this oxygen depletion phenomenon is of no practical importance. However, for CAES applications based on seasonal charge-discharge cycles and featuring plant designs that use a combustor to heat the stored air (before the expansion turbine process), it is important to assess the phenomenon. Thus the Pittsfield work suggests that a utility considering seasonal aquifer air storage for a CAES plant should evaluate both the physical and chemical characteristics of the site. It is expected that this study will be documented in a final report by mid 1986.

International CAES activities

Since 1978 the 290-MW CAES plant in Huntorf, Federal Republic of Germany, has provided up to 3.5 h of peaking and intermediate power a day for its utility owner, Nordwestdeutsche Kraftwerke Ag. The plant's performance and reliability continue to equal or exceed projections from design specifications, with a starting reliability of 99% and an availability of 90%.

The Italian national utility (ENEL) expects to begin operation of the world's second CAES plant this year at Sesta, Italy. The plant is designed specifically to test a fractured rock aquifer for CAES use; it features a 25-MW compressor train, a 25-MW motor-generator, and an expansion turbine of about 4.5 MW to get the compressor and motor-generator up to synchronous speed. If all goes well in the preliminary tests, ENEL will probably retrofit a 25-MW expander into the plant, along with a combustor and a recuperator, and convert it from a test plant to a full-fledged commercial CAES plant. EPRI has an arrangement with ENEL to share data and results from the Pittsfield and Sesta aquifer sites. EPRI is assisting ENEL where appropriate in design reviews and data analyses; also, it has provided the Italian utility with specifications for the retrofit expander and with a recommended plan for the initial plant tests. ENEL has in turn provided EPRI with details of the full plant design and geology.

Construction has begun on a 1050-MW CAES plant in the Donbass region (north of the Black Sea) of the Soviet Union. The site is in an area known for its large deposits of rock salt. The CAES plant will use salt mine caverns for storing 2 million m^3 of air at a depth of 400 to 800 m and at a pressure of 60.8 bar (6.08 MPa). Three 350-MW turbomachinery units are currently being installed.

U.S. demonstration plants

In parallel with the R&D results reported here, there has been progress in technology transfer to the utility industry: establishment of a CAES working group, continuation (under EPRI aegis) of the newsletter *CAEScope,* and, most important, planning for CAES demonstration plants. A summary of some U.S. CAES plants under consideration follows.

- Alabama Electric Cooperative initiated a preliminary engineering and geotechnical study with Gibbs & Hill, Inc., on a 50-MW CAES plant at a salt dome site, and in February its board of trustees authorized site procurement or leasing. The plant will fulfill peaking and intermediate requirements projected for the late 1980s.

- SCE has contracted Fennix & Scisson, Inc., to drill exploratory holes in a salt formation near Los Angeles for a potential 50-MW CAES plant. SCE, along with Salt River Project, Arizona Public Service Co., Nevada Power Co., and Southwest Gas Corp., is also evaluating a bedded salt system in Arizona.

- Cleveland Electric Illuminating Co. is considering a plan to use third-party ownership to construct a 50-MW CAES plant at a bedded salt site near Cleveland.

- Sacramento Municipal Utility District is currently performing siting and cost studies with Fennix & Scisson and Gibbs & Hill. The utility is considering CAES with seasonal aquifer air storage to provide electricity during refueling and unscheduled outages of its nuclear plant.

EPRI plans to assist in building the first U.S. CAES plant. Its contributions to this effort will be to mitigate technical risks; to share first-of-a-kind costs; to develop special instruments and tests for assessing plant performance; to provide a house engineer for independent review and advice; and to provide an engineer-of-record to document the experience gained during plant design, construction, startup, operation, and maintenance. *Project Managers: Robert B. Schainker and Ben R. Mehta*

R&D Status Report
NUCLEAR POWER DIVISION

John J. Taylor, Vice President

EFFECT OF NEW SOURCE TERM DATA ON EMERGENCY PLANNING

In 1978 a joint NRC–EPA task force issued a report (NUREG-0396) that presented the basis for planning emergency response efforts in the areas surrounding U.S. nuclear power facilities and introduced the concept of generic emergency planning zones (EPZs). Using the core-melt accident sequence probabilities and source term factors from the Reactor Safety Study *(WASH 1400), the report concluded that a 10-mi (16-km) radius around a nuclear power facility defined an appropriate area for which emergency response actions should be planned. (*Source term *refers to the quantities and types of radioactive materials that might be released to the outside atmosphere as a result of a severe accident at a nuclear power plant.) These response actions are intended to protect the public from the effects of an airborne plume of radioactive materials released during an accident. However, WASH-1400 results are generally considered today to be overly conservative representations of the expected source values for severe accidents. More-realistic source term values suggest that some currently required response actions may actually be unnecessary.*

In 1984 the Atomic Industrial Forum's industry degraded core rulemaking (IDCOR) program completed an independent evaluation of the source term values calculated to result from a severe nuclear power plant accident. (The IDCOR technical summary report, *Nuclear Power Plant Response to Severe Accidents,* was released in November 1984.) These new values are generally much lower than those used in WASH-1400, primarily because more-reliable data (and analytic models) of the release of fission products in a severe accident are now available. The analysis reported here was undertaken by NUS Corp. to provide a preliminary estimate of the effect of the revised source term estimates on emergency planning requirements (RP2394-14).

Effects of revised source term data

The NRC–EPA task force recommended EPZs with radii of about 10 mi (16 km) for the short-term plume exposure pathway and of about 50 mi (80 km) for the ingestion exposure pathway. To a large extent, the sizes of these zones were consistent with then-available WASH-1400 source term data. The 10-mi plume exposure EPZ was based on the following considerations.

- Projected doses from the traditional design basis accidents (DBAs) would not exceed Protective Action Guide (PAG) levels outside the zone. (The EPA plume exposure PAG dose levels are 1 rem [lower level] and 5 rem [upper level] for whole-body exposure and 5 rem [lower level] and 25 rem [upper level] for thyroid exposure.)

- Projected doses from most core-melt accident scenarios would not exceed PAG levels outside the zone.

- For the worst core-melt sequences, immediate life-threatening doses would generally not occur outside the zone.

- Detailed planning within a radius of 10 mi would provide a substantial base for expanding response efforts in the event that such expansion proved necessary.

The first of these four considerations drew on the results from DBA calculations (Regulatory Guide 1.3/1.4 and 10 CFR 100) that were performed as part of the Final Safety Analysis reports for over 70 plants. The required procedures for calculating the DBA off-site doses are both conservative and nonmechanistic (i.e., the assumptions and models are not representative of the actual physical processes governing the off-site doses for potential accidents).

The DBA dose calculation method has been in use for over 20 years, during which time only minor modifications were made to reflect new research findings. Consequently, it is generally acknowledged that the doses calculated by using the DBA method have little, if any, resemblance to the actual off-site doses that might occur as a result of a severe accident. As a result, emergency planning decisions based on the unrealistic DBA dose calculations are believed to be overly conservative.

The second and third considerations were based on the results of the severe-accident calculations performed for WASH-1400. In contrast to the DBA analysis, WASH-1400 attempted to estimate realistically the consequences and probabilities of severe accidents at nuclear power plants. However, because of the lack of certain important information (both experimental data and models for important phenomena), conservative assumptions and methods of calculation were often used. This led, of course, to results that the WASH-1400 group judged to be conservative. Following publication, substantial additional information was developed, and the technical basis for calculating the potential radionuclide releases during severe accidents was greatly improved. Consequently, the current predictions of severe-accident source term magnitude and frequency are more realistic and are subject to less uncertainty than are WASH-1400 estimates. For this study, the recently completed IDCOR severe-accident sequence source term data have been used.

The fourth consideration—that emergency planning for the area within a radius of 10 mi would provide an adequate base for ad hoc expansion of countermeasures—is not directly affected by the magnitude of the source term. The probability that there will be a need to expand emergency response efforts beyond 10 mi (or even as far as 10 mi), however, will clearly be much smaller if the source term magnitude is reduced.

Reassessing NUREG-0396 results

The effect of the IDCOR data on the NUREG-0396 conclusions was evaluated by using IDCOR (instead of WASH-1400) accident-sequence source term and sequence frequencies in calculating the off-site consequences of a severe accident. Otherwise, the same assumptions and methods were used in both analyses.

The major conclusions of these analyses are as follows.

- The second consideration—that "projected doses from most core-melt accidents would not exceed PAG levels outside the [plume exposure emergency planning] zone"—is satisfied as well at a radius of 3 mi (4.8 km) for the

IDCOR source term as it is at a radius of 10 mi (16 km) for the WASH-1400 source term for pressurized water reactors (PWRs) and boiling water reactors (BWRs).

▫ The consideration—that "for the worst core-melt sequences, immediate life-threatening doses would generally not occur outside the zone"—is met as well at a radius of 3 mi for the IDCOR source term as it is at a radius of about 10 mi for the WASH-1400 source terms for PWRs and BWRs.

▫ Using the methods and assumptions of NUREG-0396 and the IDCOR range of source terms, a plume-exposure EPZ with a radius of 3 mi or less would be justified.

Emergency response and warning time

In parallel with the above analyses, the effectiveness of various emergency responses within the 10-mi EPZ in reducing the off-site consequences of severe accidents was assessed. The emergency actions that were considered were evacuations to 1, 2, 3, and 10 mi (1.6, 3.2, 4.8, and 16 km). Calculations for each evacuation radius were based on one of two assumptions: no special protective actions outside the evacuation zone or the use of basement shelters outside the evacuation zone to a distance of 10 mi from the plant. The health effects that were considered included early fatalities, early illnesses, and latent cancer fatalities.

These analyses showed that for most core-melt accidents (using the IDCOR source term), the calculated number of early fatalities is zero or nearly zero at distances greater than about 2–3 mi (3–5 km), even without special protective action (i.e., assuming normal activities for 24 hours after plume passage). For the IDCOR worst-case source term (with a predicted probability of occurrence of less than one in a million per year), the number of early fatalities would be relatively small (fewer than 10), even without any special protective action outside 1 mi.

A 3-mi evacuation (with no special protective actions outside 3 mi) reduces the calculated number of fatalities to zero or nearly zero for the worst-case release. Hence, a 3-mi evacuation is as effective as a 10-mi evacuation in preventing early fatalities. Evacuations of 10 mi and 3 mi with special protective actions outside 3 mi, and evacuations of 1 and 2 mi with basement shelters outside the evacuation zone to a distance of 10 mi, reduce the expected number of early injuries to small values (fewer than 20), even for the worst-case accidents.

The warning times for most core-melt accidents from the IDCOR analyses are as long as or longer than those calculated in WASH-1400. The warning times for the worst-case accident sequences are typically about one-half hour to several hours for both the IDCOR and the WASH-1400 sequences.

In WASH-1400, the total release is predicted to occur within 4 hours for accident sequences with an airborne release of fission products. In the IDCOR study, releases are much slower. All predicted durations of release exceed 4 hours, and some are as long as several days. The principal reason for these durations is the time lag resulting from the deposition and subsequent revaporization of volatile fission products in the reactor coolant system.

The combination of longer warning time, longer release duration, and reduced release magnitude indicated by the IDCOR results suggests that there may not be justification for the regulation—even for the most severe core-melt accident—to notify the public within 15 minutes in order to implement effective emergency action. *Project Manager: Robert Breen*

EFFECTS OF HYDROGEN WATER CHEMISTRY ON FUEL PERFORMANCE

The intergranular stress corrosion cracking (IGSCC) of austenitic stainless steel piping in boiling water reactors (BWRs) has resulted in costly plant outages. One approach to controlling pipe cracking is to modify the water chemistry by adding hydrogen to the feedwater. This decreases the oxidizing power of the reactor water and reduces its deleterious effects on plant structural materials. However, this approach can be considered successful only if it does not adversely affect the integrity or performance of the nuclear fuel components.

Adding hydrogen to the water of BWRs creates a water chemistry in the reactor core that is outside the experience base of either BWRs or pressurized water reactors (PWRs). Because the corrosion behavior of the zirconium-based alloys (Zircaloys), which are used almost exclusively in the high-flux regions of water-cooled reactors, depends strongly on the reactor water chemistry, it is necessary to verify that the integrity of the fuel components is not compromised by the presence of added hydrogen. In particular, the corrosion of the cladding tubes that separate the coolant water from the nuclear fuel and the embrittlement of the structural components that keep the fuel rods evenly spaced from one another are key performance considerations.

In most projected regimes of corrosion behavior during operation under the conditions of hydrogen water chemistry (HWC), the effects of the added hydrogen are expected to be small. However, for some regimes, such as for Zircaloy-2 fuel cladding that experiences BWR water chemistry oxidation rates and PWR water chemistry hydrogen pickup rates, the loss of cladding ductility caused by hydrogen-induced embrittlement could be severe. Another area of uncertainty is related to the hydriding of those BWR fuel elements that would first be exposed to a normal water chemistry environment (for one or two reactor cycles) before being exposed to an HWC environment.

Fuel surveillance program

The objective of the fuel surveillance program is to detect, identify, and assess any material characteristic that could degrade the performance of fuel assemblies operated in commercial BWRs in which hydrogen is intentionally added to the reactor feedwater (RP1930-10). Of particular interest are the effects of the added hydrogen on oxidation and hydriding of the Zircaloy components, as well as on crud deposition rates and characteristics.

Four lead test assemblies fabricated by General Electric Co. were inserted into the Dresden-2 reactor of Commonwealth Edison Co. at the beginning of the first cycle of hydrogen addition (cycle 9). The lead test assemblies include Zircaloy-2 and -4 with precharacterized ranges of corrosion behavior that are representative of those usually found with cladding batches used in General Electric's BWR fuel. The precharacterization of the Zircaloy materials was on the basis of a high-temperature, high-pressure test, the results of which tend to correlate well with in-reactor corrosion behavior.

In addition, three fuel bundles that have been or will be exposed to various combinations of normal water chemistry and HWC have been selected for postirradiation examinations. All three bundles are made of fuel components for which few or no precharacterization data exist; the basis for the selection lies in their power histories, which are similar and are among the most severe for the Dresden-2 reactor.

In the ongoing fuel surveillance program, a combination of site and hot cell examinations provides for the following activities.

▫ Site examination: visual assessment of the overall bundle condition; visual determination of nodular corrosion coverage; eddy-current determination of oxide thickness; crud scraping

▫ Hot cell examination: metallographic determination of oxide thickness and of nodular oxide coverage; metallographic determination

Figure 1 Photomicrograph showing the uniform and nodular oxide formed on one of the lead test assembly spacers. Nodules typically assume a lenticular shape.

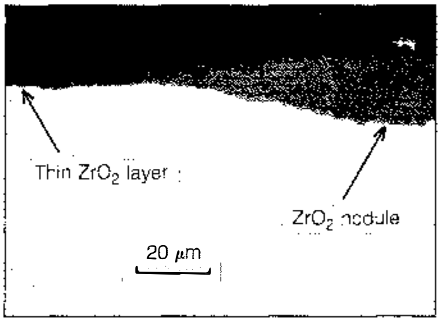
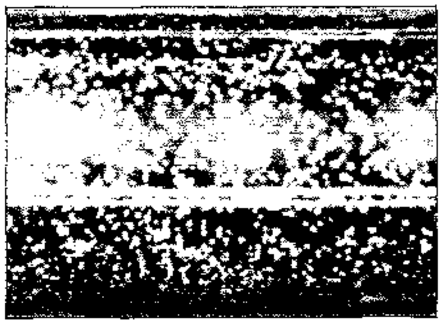


Figure 2 Appearance of a UO_2 rod from the lead test assembly (rod diameter: ~0.5 in [12.5 mm]) at 100 in (254 cm) from the bottom of the rod. Oxide nodules are readily visible as white spots.



of hydrogen distribution; hot extraction determination of hydrogen content; crud analysis

Although significant HWC-induced changes in the corrosion behavior of the Zircaloy would be apparent during the site examinations, information on Zircaloy hydriding cannot be properly quantified except by destructive examination in hot cells.

The components examined were urania and urania-gadolinia fuel rod claddings (Zircaloy-2), spacers (Zircaloy-4), and water rods (Zircaloy-2).

No examinations were conducted prior to the start of cycle 9, at which time hydrogen was first added; however, a three-cycle bundle discharged at the end of cycle 8 was selected as the reference bundle. This reference bundle (designated as 3-0—that is, three cycles in normal water chemistry and none in HWC) was examined at the end of cycle 9, together with a 2-1 discharged bundle and one of four 0-1 lead test assemblies. At the end of cycle 10, another discharged bundle (1-2) and one of the four lead test assemblies (0-2) will be examined. At the end of cycle 11, corresponding to three cycles of HWC, the four lead test assemblies will be available for detailed examination; such work is considered optional at this time.

Hydrogen addition

During the first cycle with hydrogen added to the feedwater, the oxygen concentration in the recirculation piping was kept below 20 ppb during 80% of the time the reactor was operated at more than 25% of nominal full power. Therefore, the fuel was exposed to a well-established HWC environment for about 80% of the time; during the remaining 20% of the time the actual reactor water chemistry varied between the limits defining normal water chemistry and HWC.

The 3-0 reference bundle, a 2-1 bundle, and one of the lead test assemblies were first examined nondestructively at the reactor site. On the basis of the poolside examination, a number of fueled and unfueled components were selected, shipped, and destructively examined in the hot cells of General Electric's Vallecitos Nuclear Center.

In a typical BWR environment, oxidation of Zircaloy produces (1) a thin layer of zirconia (ZrO_2) that uniformly covers the Zircaloy surfaces in contact with water, and (2) nodules that result in locally thicker patches of zirconia (Figures 1 and 2). As exposure time increases, the nodules may grow and coalesce, resulting in uniformly thick oxide layers.

Results available so far indicate that the overall amount of oxide is, as expected, significantly lower on the lead test assembly rods than it is on the three-cycle rods. Measured uniform oxide thicknesses are only 1–2 μm on the lead test assembly rods, whereas they are 8–12 μm on the three-cycle rods. Maximum local oxide thicknesses arising from the presence of nodules, however, are similar in all rods (~30 μm), a somewhat surprising result.

In a typical BWR environment and with good fuel manufacturing practices, hydrogen pickup by the cladding is primarily a result of the oxidation reaction

$$Zr + 2H_2O \rightarrow ZrO_2 + 2(1 - x)H_2 + 4xH$$

where the second right-hand term is hydrogen released to the coolant and the third is hydrogen retained in the Zircaloy; x is the hydrogen pickup (about 0.1 for Zircaloy-2, and -4 under typical conditions).

Present results indicate that hydrogen levels in all the Zircaloy components examined at the end of cycle 9 are low and correlate well with the overall extent of oxidation. Therefore, the presence of hydrogen in the coolant has not resulted in a detectable increase in hydrogen pickup by the Zircaloy material.

Excessive crud deposition accompanied by the formation of tenacious crud deposits can be very detrimental to the performance of the Zircaloy cladding. Results thus far indicate that the iron surface concentration in the crud deposits accounts for more than 95% of the total surface concentration of all metallic elements detected in the deposits for all three bundles.

The total measured crud deposits and the distribution and magnitude of ^{60}Co deposits are roughly equivalent for the 3-0 and 2-1 bundles; in relation to the 3-0 bundle, however, the 2-1 bundle has a higher percentage of tightly adherent deposits, as well as higher concentrations of copper in those deposits.

The loosely and the tightly adherent deposits in bundle 0-1 are lower by factors of two to four than those on the two 3-cycle bundles; also, the copper, nickel, cobalt, zinc, and manganese surface concentrations are much lower in the 0-1 bundle than they are in the three-cycle bundles. The results also show a possible tendency for the location of the peak crud deposit to be shifted upward with HWC.

Overall, crud deposition characteristics are still in the normal range, and there are no indications of any adverse effects on fuel performance.

Assessment

After one cycle of hydrogen water chemistry, the results indicate that for all three bundles (3-0, 2-1, and 0-1) the oxide layers and hydrogen concentrations are well below levels that would cause concern about fuel performance. Further, within the limits of experimental uncertainties, it does not appear that hydriding rates are directly influenced by the presence of hydrogen in the coolant. A few differences, especially in crud deposition, are observed, but they do not constitute a threat to the integrity of the fuel bundles at a plant such as Dresden-2. Additional examinations after two and three cycles of hydrogen water chemistry are necessary to confirm observations made so far.

This preliminary assessment, which indicates little or no effect of HWC on fuel performance, cannot yet be extended to BWRs characterized by the presence of high concentrations of copper in the reactor water. As indicated by the Dresden-2 results and by those from a number of tests of short duration in other reactors, the less-oxidizing environment promoted by adding hydrogen tends to lead to a reduction of and a more efficient deposition of such species as copper and chromium. Assuming that the deposition occurs primarily on the fuel surfaces, the HWC environment could accelerate the Zircaloy oxidation rates, especially in older fuel that would be exposed to the transition from normal to hydrogen water chemistry. *Project Manager: Albert Machiels*

New Contracts

Project	Funding and Duration	Contractor and EPRI Project Manager
Advanced Power Systems		
Carrier-Lifetime-Limiting Mechanisms in Silicon (RP790-13)	$108,200 11 months	Georgia Tech Research Corp.; *F. Goodman*
High-Concentration Photovoltaic Module Producibility (RP1415-10)	$85,400 5 months	Foster-Miller, Inc.; *R. Taylor*
Geothermal Brine Crystallizer Test at Cerro Prieto (RP1525-7)	$167,200 12 months	Instituto de Investi-gaciones Eléctricas (Mexico); *J. Bigger*
Wind Power Commercial Status Survey (RP1590-9)	$44,400 9 months	Strategies Unlimited; *F. Goodman*
Assessment of Wind Power Station Performance and Reliability (RP1590-10)	$370,500 24 months	R. Lynette & Associates, Inc.; *F. Goodman*
Assessment of Kahuku Point Wind Turbine Performance (RP1590-11)	$214,900 19 months	Hawaiian Electric Co., Inc.; *F. Goodman*
Photovoltaic Field Test Analysis (RP1607-6)	$92,000 12 months	New Mexico State University; *J. Schaefer*
Operation and Maintenance Data Requirements for Geothermal Power Plants (RP1991-2)	$63,600 7 months	Pickard, Lowe and Garrick, Inc.; *J. Bigger*
Sulfur Distribution During Coal Devolatilization and Gasification (RP2051-2)	$40,200 8 months	Westinghouse Electric Corp.; *R. Frischmuth*
Wood-Burning Gas Turbine Performance at Red Boiling Springs (RP2612-9)	$35,000 5 months	Aerospace Research Corp.; *D. Augenstein*
Stream Characterization Studies During the High Ash-Fusion Maryland Coal Gasification Test (RP2659-7)	$157,800 9 months	Tennessee Valley Authority; *N. Hertz*
Long-Term Leaching of High-Ash-Fusion Maryland Coal Slag (RP2659-8)	$57,500 24 months	Tennessee Valley Authority; *N. Hertz*
Fundamental Physiochemical Principles of Coal-Water-Slurry Gasifier Feedstocks (RP2696-2)	$411,100 24 months	Adelphi Research Center, Inc.; *L. Atherton*
Definition of Baseline and Advanced Power Electronic Drives for Wind Turbine Applications (RP2790-2)	$82,300 6 months	Westinghouse Electric Corp.; *F. Goodman*
Fundamental Studies of Heavy Fuel Liquids: Coke Particulate Formation and Destruction During Combustion (RP8005-1)	$320,200 36 months	Princeton University; *W. Rovesti*
Coal Combustion Systems		
Flue Gas Conditioning Decomposer Installation (RP724-4)	$216,300 14 months	Black & Veatch Engineers-Architects; *R. Altman*
Assessment of Coal-Fired Power Generation Technologies (RP1180-17)	$40,000 9 months	Stearns Catalytic Corp.; *C. McGowin*
Benefits of Coal Combustion Systems R&D to the Utility Industry (RP1180-18)	$30,000 4 months	Applied Decision Analysis, Inc.; *C. McGowin*
Microcomputer Model for Water-Softening Systems (RP1261-13)	$276,400 15 months	Brown & Caldwell; *W. Micheletti*
Advanced Coal-Cleaning Technologies (RP1338-9)	$41,500 5 months	Norton, Hambleton, Inc.; *R. Row*
Turbine R&D for Advanced Fossil Fuel Power Plants (RP1403-15)	$4,092,100 40 months	General Electric Co. and Toshiba Co.; *G. Touchton*
Spray Dryer Design and Construction for Integrated Environmental Control and Pilot Plant Tests (RP1646-7)	$271,600 7 months	Raymond Kaiser Engineers, Inc.; *E. Cichanowicz*
Full-Scale Demonstration of Dry Sodium Injection (RP1682-6)	$356,000 10 months	Radian Corp.; *R. Hooper*
Modification of Bull Run Electrostatic Precipitator Facility (RP1835-11)	$140,500 3 months	Production Maintenance Corp.; *R. Altman*
Slag Monitoring Techniques for Utility Boilers (RP1893-5)	$90,000 9 months	Battelle Memorial Institute; *J. Scheibel*
Evaluation of Eddy-Current Tests (RP1957-5)	$244,700 12 months	General Electric Co.; *J. Scheibel*
Instrumentation Guidelines for Integrated Power Plant Water Management Systems (RP2114-6)	$172,400 12 months	CH2M-Hill California, Inc.; *W. Micheletti*
Assessment of NO_x Control Options for Cyclone Boilers (RP2154-9)	$67,000 8 months	Fossil Energy Research Corp.; *G. Offen*
Interaction of Chemistry and Fluid Mechanics in NO_x Formation During Coal Combustion (RP2154-10)	$135,000 12 months	Stanford University; *G. Offen*
Field Testing of Behavioral Barriers for Cooling-Water Intake Structures (RP2214-5)	$243,800 18 months	Ontario Hydro; *W. Micheletti*
Atmospheric Fluidized-Bed Combustion Cost and Performance Evaluation Code: AFBTREE (RP2303-12)	$69,300 13 months	Decision Focus, Inc.; *S. Tavoulareas*
Development of Dry Sorbent Emission Control Techniques for SO_2 Reduction (RP2533-7)	$403,600 13 months	KVB, Inc.; *G. Offen*
Colorado-Ute Test Program Engineering and Installation (RP2683-4)	$1,795,600 27 months	Stearns Catalytic Corp.; *C. Lawrence*
Engineering and Construction Management for CCTF Modification in Support of Advanced Fine-Coal-Cleaning Technologies (RP2704-1)	$125,500 7 months	Kaiser Engineers, Inc.; *C. Harrison*
Instrumentation and Control for Fossil Fuel Plant Cycle Chemistry (RP2712-2)	$216,400 8 months	Sheppard T. Powell Associates; *B. Dooley*

Project	Funding and Duration	Contractor and EPRI Project Manager
Design and Engineering for 10-MW Baghouse Calcium Injection System (RP2784-2)	$52,600 5 months	Stearns Catalytic Corp.; *M. McElroy, R. Rhudy*
Engineering Support for Humidification and Calcium Injection Tests Upstream of an Electrostatic Precipitator (RP2786-1)	$57,800 3 months	Raymond Kaiser Engineers, Inc.; *M. McElroy*
Robotics Applications in Fossil Fuel Plants (RP2819-1)	$49,900 5 months	Arthur D. Little, Inc.; *J. Scheibel*
Interaction of Chemistry and Fluid Mechanics in NO_x Formation During Coal Combustion (RP8005-2)	$734,600 36 months	Stanford University; *G. Offen*

Electrical Systems

Project	Funding and Duration	Contractor and EPRI Project Manager
Reliability-Based Design of Transmission Line Structures: Nondestructive Evaluation Techniques (RP1352-4)	$87,400 12 months	Engineering Data Management, Inc.; *P. Lyons*
Voltage Stability and Security Assessment (RP1999-8)	$49,900 13 months	Michigan State University; *J. Mitsche*
Validation of Generator Field Testing and Modeling Techniques (RP2328-2)	$86,100 14 months	Ontario Hydro; *J. Edmonds*
Fabrication Techniques for Motor Laminations Using Amorphous Iron (RP2366-1)	$201,400 13 months	Reliance Electric Co.; *J. Stein*
Transmission Line Research at HVTRF (RP2472-3)	$4,647,000 37 months	General Electric Co.; *J. Dunlap*
Uncertainty and Risk Minimization in Electric Resource Planning (RP2537-1)	$326,700 18 months	Power Technologies, Inc.; *N. Balu*
Composite System Reliability Evaluation: Phase 1, Scoping Study (RP2581-1)	$153,600 10 months	Public Service Electric & Gas Co.; *N. Balu*
Insulator Aging in Gas-Insulated Bus (RP2669-2)	$400,000 38 months	Westinghouse Electric Corp.; *F. Garcia*
Advanced HVDC Control and Protection (RP2675-3)	$457,200 18 months	General Electric Co.; *S. Wright*
Evaluation of Software Development Tools (RP2715-1)	$141,900 18 months	ORI, Inc.; *J. Lamont*
Series Connection of Gate Turn-off Thyristors (RP2745-1)	$145,000 17 months	General Electric Co.; *H. Mehta*
New Oilborne Wood Preservative Systems (RP2797-1)	$686,400 83 months	Forest Products Utilization Laboratory; *J. Dunlap*
Fault Location System for Transmission-Type Cable (RP7874-3)	$194,100 8 months	Public Service Electric & Gas Co.; *F. Garcia*

Energy Analysis and Environment

Project	Funding and Duration	Contractor and EPRI Project Manager
Electric Field Teratology Study in Rats (RP799-22)	$827,500 17 months	IIT Research Institute; *R. Patterson*
Gaseous Effluent From Coal Gasification Solid Waste (RP1617-4)	$34,700 13 months	Tennessee Valley Authority; *J. Guertin*
Methods for Incorporating Financial Constraints in Utility Investment Planning (RP1920-3)	$148,500 23 months	Putnam, Hayes & Bartlett, Inc.; *S. Chapel*
Potential Impacts of Climate Change on Electric Utilities (RP2141-11)	$50,000 6 months	ICF Incorporated; *C. Hakkarinen*
Residual Fuel Oil Quality: Market Trends and Utility Options (RP2369-60)	$133,000 5 months	The Pace Consultants; *H. Mueller*
Review of Organic Substance Migration Models (RP2377-5)	$46,800 23 months	University of Michigan; *I. Murarka*
Instream Flow Needs: Research Planning Workshop (RP2380-14)	$39,800 4 months	EA Engineering, Science, and Technology, Inc.; *J. Mattice*
Role of New Technologies in Utility Business Strategies (RP2631-1)	$424,600 20 months	Applied Decision Analysis, Inc.; *S. Chapel*

Project	Funding and Duration	Contractor and EPRI Project Manager
Response of Plants to Interacting Stresses (RP2799-1)	$2,631,400 71 months	Boyce Thompson Institute for Plant Research; *R. Goldstein*

Energy Management and Utilization

Project	Funding and Duration	Contractor and EPRI Project Manager
Flywheel Energy Recovery System: Feasibility Study (RP1084-20)	$25,000 8 months	Philadelphia Gear Corp.; *R. Schainker*
Development of Molten-Carbonate Fuel Cell Cathodes (RP1085-12)	$282,100 34 months	Case Western Reserve University; *J. Appleby*
Fluoropolymer Sulfonic Acids for Phosphoric Acid Fuel Cell Cathodes (RP1676-8)	$110,400 22 months	Texas A&M Research Foundation; *J. Appleby*
EPRI Roles in Fuel Cell Commercialization (RP1677-15)	$250,600 9 months	Decision Focus, Inc.; *J. Birk*
New Power Semiconductor Devices: Performance and Applications (RP1966-15)	$242,100 11 months	Westinghouse Electric Corp.; *R. Ferraro*
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Freeze Concentration of Dairy Products (RP2782-1)	$232,500 14 months	Dairy Research, Inc.; *A. Karp*

Nuclear Power

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Steam Generator Corrosion Assessment Tests (RPS309-4)	$99,100 6 months	Combustion Engineering, Inc.; *C. Williams*
Fiber-Optic Probe for Water Impurities (RP1447-4)	$54,400 6 months	University of Arizona; *T. Passell*
Industry-University Cooperative Research Program Center for Nondestructive Evaluation (RP1570-15)	$35,000 12 months	Iowa State University; *G. Dau*
Leak-Before-Break Criteria Development (RP1757-54)	$55,200 4 months	Combustion Engineering, Inc.; *D. Norris*
Leak-Before-Break Guidelines (RP1757-55)	$59,200 4 months	Westinghouse Electric Corp.; *B. Chexal*
Analysis of Advanced Digital Feedwater Control System With MMS Code (RP2126-6)	$95,600 28 months	Tennessee Valley Authority; *M. Divakaruni*
LACE Code Experiment Comparison (RP2135-18)	$420,000 25 months	Martin Marietta Energy Systems; *F. Rahn*
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EPRI Project Manager: R. Squitieri

TECHNICAL INFORMATION

Digest of Research in the Electric Utility Industry
TI-4408-SR Special Report, Vols. 3–5; $75.00 for three-volume set
EPRI Project Manager: P. Bates

CALENDAR

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

JUNE

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

2–4
Seminar and Exposition: Assuring Power Quality
San Francisco, California
Contact: Marek Samotyj (415) 855-2980

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

2–6
Seminar: High-Voltage Transmission Line Design
Lenox, Massachusetts
Contact: John Dunlap (415) 855-2305

3–5
Seminar: Chemical Decontamination of BWRs
Charlotte, North Carolina
Contact: Christopher Wood (415) 855-2379

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

18–20
5th Symposium: Analytical Chemistry (cosponsored by EPRI, DOE, and NSF)
Provo, Utah
Contact: Jacques Guertin (415) 855-2018

18–20
Pressurized Fluidized-Bed Combustion Power Plants
Milwaukee, Wisconsin
Contact: Steven Drenker (415) 855-2823

24–26
Seminar: Transmission Line Design Optimization
Schenectady, New York
Contact: Richard Kennon (415) 855-2311

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

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