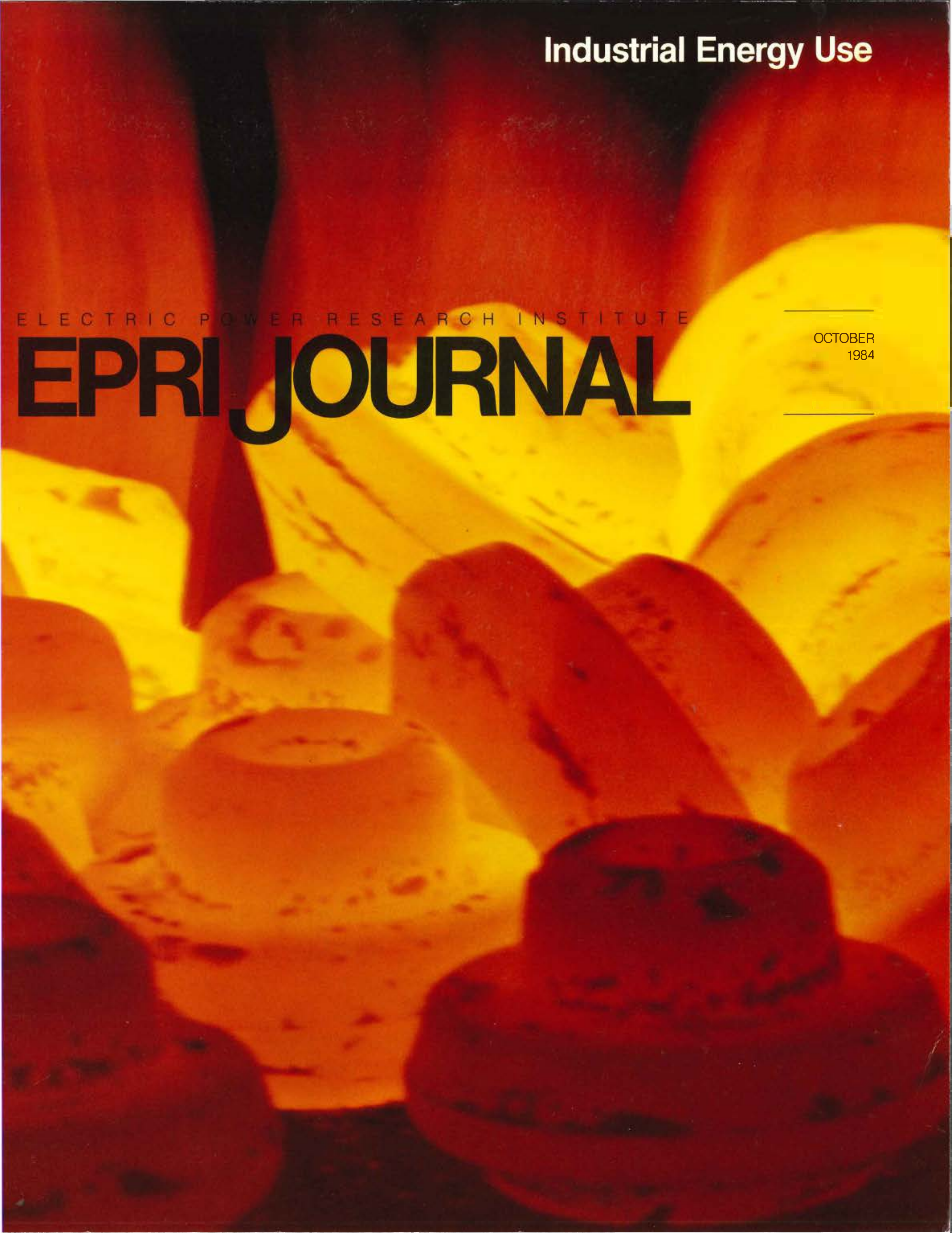
Industrial Energy Use

ELECTRIC POWER RESEARCH INSTITUTE

EPRI JOURNAL

OCTOBER
1984



EPRI JOURNAL is published monthly, with the exception of combined issues in January/February and July/August, by the Electric Power Research Institute. The April issue is the EPRI *Annual Report*.

EPRI was founded in 1972 by the nation's electric utilities to develop and manage a technology program for improving electric power production, distribution, and utilization.

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Ray Schuster, Director
Communications Division

Address correspondence to:
Editor in Chief
EPRI JOURNAL
Electric Power Research Institute
P.O. Box 10412
Palo Alto, California 94303

Cover: Process heating is one of many areas in which electrotechnologies are making competitive inroads in industry. Shown are oil well drill bit cones that have been heated in an electric oven prior to being drop-forged, machined, and inset with tungsten carbide cutting buttons.

EPRI JOURNAL

Volume 9, Number 8 October 1984

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Working Smarter With Electricity

Like so many other goods and services, electricity isn't likely to get cheaper in today's economy. But the way it is used can do much to cut the cost of both industrial and consumer products. Time and again, the course of technologic change shows that new, electricity-based industrial processes lead to sharp savings of time, labor, and materials. These new processes may save energy, or they may be more energy-intensive than those they replace. Phrased another way, the overall result is greater economic output for a given set of inputs; in short, better productivity. This month's cover story expands on this topic and notes its special significance for the electric utility industry.

Time was when we looked at electricity simply as a product, usable only in narrowly defined ways—mostly lights and motors. Today we think more broadly, considering instead the services electricity performs. Heat pumps keep people comfortable with warm air in the winter and cool air in the summer. Lasers deliver intensely focused energy to heat and cut materials with unprecedented speed and precision. Electronic impulses cascade through the digital logic paths of computer programs, controlling machinery and processes in such varied and complex sequences that they seem to think as well. Truly, electricity is a means for working smarter, not just harder.

Recognizing this, industrial managers are looking to these new technologies for leverage in the productivity of manufacturing operations. Electric utilities are also becoming aware of their strategic role in productivity improvement, and EPRI is serving as a focus for the cooperative development of cost-competitive technologies for electricity end use, not to mention showcasing the information base that documents electricity as the most productive energy service available. As a practical matter for the utility industry, this strategy deals with two timeframes.

Near-term development and marketing focus on electrotechnologies that maximize the use of power from existing plants. Because of the recent recession, as well as the completion of construction programs begun a dozen or more years ago, many utilities have generating capacity available to serve new markets. In this setting, near-term electrotechnologies may need to beat the competition of other fuels on a dollar basis, without considering electricity's special advantages.

The longer-term strategy depends on entirely new ways of using electricity, in which its high quality, flexibility, and controllability play indispensible roles. Where the productivity of a machine, process, assembly line, or plant is increased as a result, the higher unit cost of the electric energy itself is clearly tolerable.

Electricity's implications for greater industrial productivity and competitive capability make end-use technology research important to the entire nation. Electric utilities (and EPRI on their behalf) have an increasingly apparent responsibility for that effort. Happily, the opportunities are nearly boundless, and an early challenge for EPRI has been to select and shape the R&D that will be most effective.

For the twin goals of national economic health and vigorous local economies, the first responsibility of U.S. electric utilities is, as always, to deliver an adequate supply of electricity. But in the close economic atmosphere of the 1980s, they also have a new and special responsibility—that of fostering technologies by which electricity provides the most productive energy service available to industry.

Thomas R Schneider

Thomas R. Schneider, Director
Energy Utilization and Conservation Technology
Energy Management and Utilization Division

Authors and Articles

Considered simply another form of energy for 100 years, electricity is now seen for other qualities, which are opening the door to new industrial processes, even entire technologies. In **Electricity: Lever on Industrial Productivity** (page 6), feature editor Ralph Whitaker presents examples, trends, and a logic linking electricity use with economic growth. Three energy and two economic researchers supplied information.

Thomas Schneider, Leslie Harry, and Alan Karp are with EPRI's Energy Utilization and Conservation Technology Department. Schneider, the department director since January 1982, came to EPRI five years earlier to manage a research program in energy storage. He was formerly with New Jersey's Public Service Electric and Gas Co., where he directed R&D in a number of energy conversion, storage, and end-use technologies. Schneider holds a doctorate in physics from Stevens Institute of Technology.

Harry and Karp are managers of research projects in electrotechnologies. Before joining EPRI in April 1980, Harry was a consultant with Scientific Applications, Inc. Earlier, between 1971 and 1978, he was with DOE, becoming a program manager in the Office of Conservation. He graduated from Western Kentucky University in physics and mathematics, has an MS in nuclear engineering from Georgia Institute of Technology, and an MBA from Stanford University.

Karp began work with EPRI as a consultant in September 1982 and became a staff member in December 1983. Since 1967 he had held process design and project responsibilities with Exxon Research and Engineering Co., Imperial Oil Enterprises, Ltd., Fluor Engineers, Inc. and Bechtel Petroleum, Inc. Karp holds BS and MS degrees in chemical engineering from Stevens Institute of Technology and the University of Michigan.

Sam Schurr and Milton Searl are economists with EPRI's Energy Study Center. Schurr, the deputy director since March 1979, had been with EPRI earlier as founding director of the Energy Analysis and Environment Division from 1973 to 1976. In between and for 19 previous years Schurr was with Resources for the Future, Inc., first as director of the energy and mineral resources program and later as codirector of the RFF center for energy policy research.

Searl came to EPRI in December 1973 and headed the Energy Supply Studies Program until August 1979, when he joined Schurr as a technical manager in the Energy Study Center. Searl was formerly with RFF for two years and before that with the Office of Science and Technology as chief economist of the energy policy staff. Still earlier, he was with the Atomic Energy Commission for nine years, becoming chief economist.

■

Technology that has a lower price tag than its predecessor is always welcome. **New Transformers: Nontoxic, Nonflammable** (page 16) reviews R&D that is producing such a result in the form of fluids to take the place of PCBs for cooling and insulating transformers. The article was written by Stephen Tracy, science writer, and is based on interviews with two research managers of EPRI's Electrical Systems Division.

Edward Norton, project manager in the Transmission Substations Program, has specialized in transformer development, design, and application for more than 30 years. Before coming to EPRI in January 1975, he had been with Allis-Chalmers Corp. since 1953, becoming manager of power transformer applications. Norton is an electrical engineering graduate of the Polytechnic Institute of Brooklyn.

Robert Tackaberry, project manager in the Distribution Program, has been with EPRI since February 1976. He was formerly with A. B. Chance Co. for 10 years, most of that time as marketing manager. From 1952 to 1965 he was in applications and marketing management with Joslyn Manufacturing and Supply Co. Tackaberry is a graduate of the U.S. Naval Academy.

■

Fatigue and corrosion damage that would be accepted in a nuclear steam generator after 30 or 40 years calls for expensive detective work when it occurs in fewer than 10 years. **Longer Life for Steam Generators** (page 20) reports on the origins and conduct of specially commissioned research that has already cut the incidence of one problem—tube denting—by a factor of 9. The article is the work of science writer John Douglas, aided by Stanley Green.

Green came to EPRI's Steam Generator Project Office as a senior program manager in August 1977, and he has been director of the office since 1979. Formerly with the Bettis Laboratory of Westinghouse Electric Corp. for 23 years, he was manager of thermal and hydraulics engineering for much of that time and eventually became manager of reactor development and analysis. Green earned his doctorate in chemical engineering at the University of Pittsburgh.

■

Another laboratory-in-a-suitcase has come on the scene, this one for fast, accurate data on the thermal characteristics of soils along underground cable routes. **Thermal Analysis of Soils** (page 28) reviews a device that saves time and money in the field and makes possible more cost-effective cable designs. Science writer Stephen Tracy was the author, aided by EPRI's Thomas Rodenbaugh.

A project manager in the Underground Transmission Program, Rodenbaugh has been with the Institute since August 1974, much of his work concerned with the physics of materials and their effect on the performance of electrical apparatus. Rodenbaugh holds a BS in physics from the University of California, Berkeley, and an MS in solid-state physics from San Jose State University.


Schneider


Green


Schurr


Harry


Rodenbaugh


Searl


Norton


Karp


Tackaberry

Productivity in the United States is only inching upward these days. Between 1953 and 1973, the classic index—a ratio of gross national product (GNP) to civilian labor hours—increased an average of 2.3% annually. But for the following 10 years, it was virtually flat at 0.5%.

During the past two years productivity has improved slightly, but this cannot yet be called a new trend. Economists say that a spurt always marks the turnaround years of recovery from an economic recession; because business belts are tight, expenses of all kinds are cut back.

Now the question is how to restore the momentum of long-term productivity growth as belts are loosened and resources flow again. Organizational structure and management practices, as well as materials and technologies, are subjects of study, experimentation, and implementation. The objective is to increase economic output, the GNP, faster than the sum of major inputs, which are separately distinguished today as labor, capital, materials, and energy.

Leslie Harry, a project manager in the Industrial Program of EPRI's Energy Utilization and Conservation Technology Department, emphasizes the pivotal role of energy. "Even before the seventies, manufacturers in other countries had learned to be competitive despite their high cost of energy. But energy was a low-cost item here—artificially so, some would say—until the energy crisis suddenly sent our costs straight up. When that happened, foreign goods turned out to be better priced than our own, and the flood of imports was on, a real factor in the U.S. recession."

Electricity and growth

Electric utilities are caught up in today's industrial renaissance. They have a stake in any game that advances the economic vitality of their market areas; being geographically defined, they cannot go elsewhere for business. Also, many principal players are major utility customers: large, well established, and energy-intensive. Through their payrolls and their patronage of other local enterprises, those customers are central to the economic health of utility service territories and thus to utilities.

Even so, improved productivity does not mean greater electricity consumption in every process or by every industry. There is another, more inclusive reason for utility interest, inquiry, and R&D in the end uses of electricity. It is the substantial evidence that on a nationwide basis economic growth and increasing electricity use go hand in hand. Empirical data covering more than 80 years prove the point.

Statistical analyses by Milton Searl of EPRI's Energy Study Center reveal lengthy periods during which uniform increments of added electricity consumption accompanied each dollar of GNP growth. Moreover, the average increment was larger for each succeeding period. Since World War II, the electricity increment has been 2.14 kWh for the U.S. economy as a whole and 2.43 kWh for industry alone; that is, 2.43 more kWh were used by industry for each added dollar of industrial output.

Such a trend explains why industrial managers are looking to new, electricity-based technologies, not just minor improvements in old ones, for real leverage on productivity. Charles Berg, one-time chief engineer of the Federal Power Commission and now an energy consultant and chairman of mechanical engineering at Northeastern University, emphasizes that cutting energy use alone does not restore productivity to competitive levels. "Although a conservation measure may cost less than the fuel it saves, the fuel still needed must be valued at its present or future price. But the plant or process was designed when fuel cost much less." Therefore, according to Berg, the combined costs of conservation and fuel remain higher than the amount seen to be profitable in any production design that is more than a year or so old, and productivity still falls short.

Data on U.S. industrial productivity growth do not distinguish between the productivity of industries and processes that have been electrified and the productivity of those that have not. But there is other evidence for the beneficial influence of electrification. It can be seen in the concept of form value. This term was coined as an umbrella for several attributes of electricity that affect the quantity, arrangement, use, and value of other factors of production.

Motors on individual production machines, for example, demonstrate the flexibility of electricity use made possible by the literal flexibility of electric wire and cable. Until about 70 years ago the controlling logic for factory layout was the rigidly geometric pattern of shafts and belts by which power was transmitted from a prime mover. Introduction of so-called unit drives changed forever the configuration of manufacturing operations, yielding all manner of efficiencies and economies as processes were rearranged for the logical and expedient movement of materials.

The worksite efficiency of electricity is part of its form value. Virtually 100% of electric energy is applied to the task at hand. What's more, there is essentially no waste heat requiring yet another energy expenditure for disposal, and the user is not encumbered with the special plants and processes (and investments) for energy conversion. Together, these facts do much to compensate for the energy that is inevitably lost in generating electricity from various primary fuels.

Controllability and precision of application are aspects of form value. Electricity can be focused to a degree possible with no other kind of energy, turned quickly on and off, and delivered in exactly measured amounts; among other things it can apply a specific degree of heat at a desired point inside a material. Intensity is a related attribute. Other energy processes are generally limited to about 3000°F (1650°C), but electricity can induce temperatures above 10,000°F (5540°C).

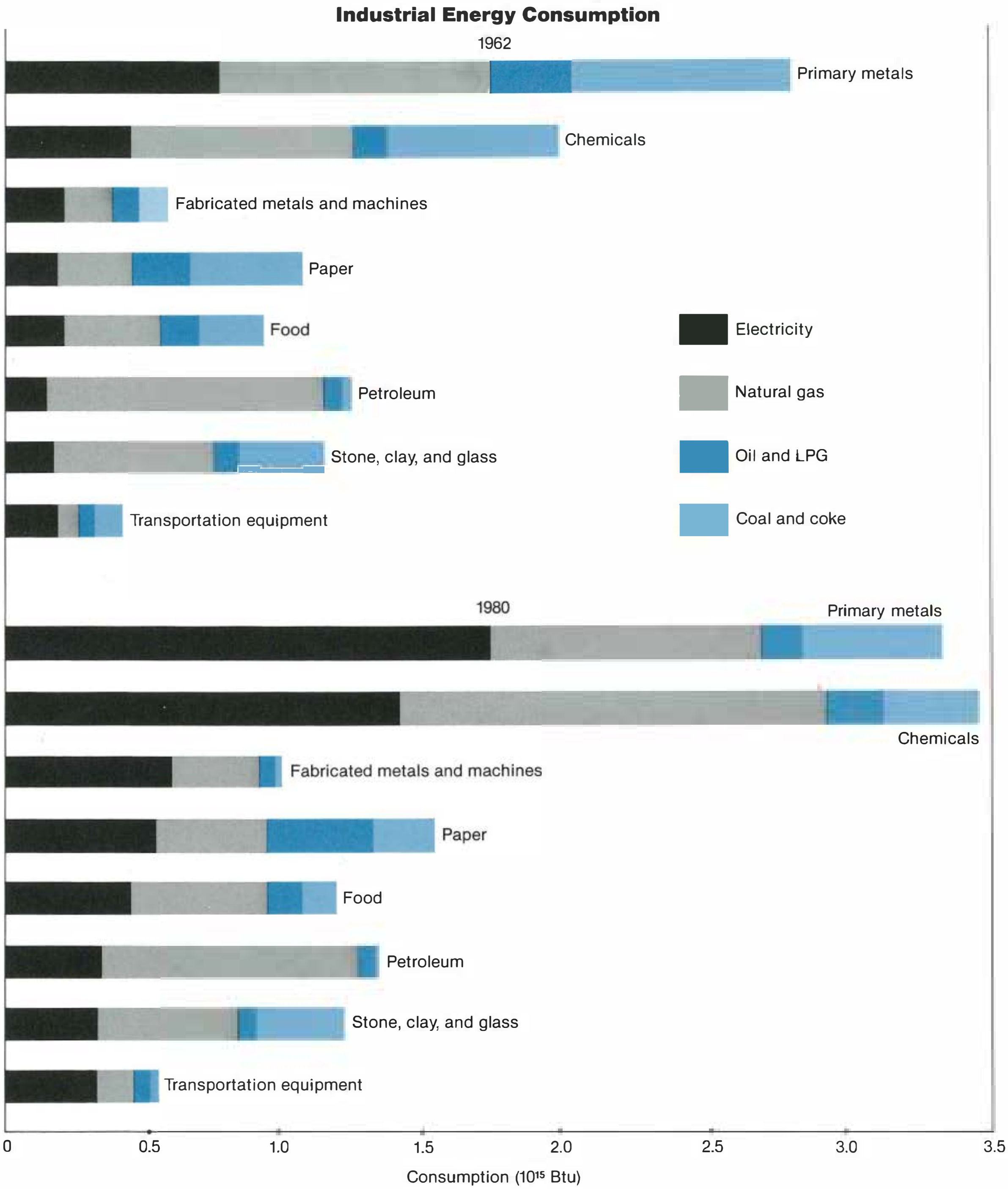
The leverage of computers

Electricity's form value does not in all, or even most, instances imply less energy use. Berg's research tells him that technology innovators are motivated to enhance productivity in general, not simply to economize on some one or another factor. He reports, for example, that labor requirements are likely to go up with the first use of new technology, only to fall further than any other factor of production as the new scheme is refined.

Indeed, when every production input seems to fall, it is often only in relative terms, the result of an increase in output. Electrification, for example, generally brings precision and fine control to production, thus contributing to reduced losses and higher output yields of acceptable quality. It very frequently also makes for greater speed (and greater throughput), thereby leveraging the productivity of other factors that have individually changed only a little.

Michael Bergman, staff scientist, and Eric Leber, director of energy research for the American Public Power Association, compiled a number of examples for an EPRI workshop in October 1983. In the production of steel billets, heating in an electric induction furnace takes several minutes; in a combustion furnace, several hours. Lumber can be kiln-dried in 1 day by microwave versus 25 days by gas. Containers (tin cans) with inked labels are cured under ultraviolet light in 1 second, whereas cans with painted labels need 8 minutes in an oven. Electromagnetic waves cure rubber in seconds or minutes rather than hours, dry paper up to 1.5 times faster, and fix the dyes on textiles as much as 6 times faster. And commercial bakers, like homemakers, know that

Electricity consumption continues to rise in U.S. industry, not only in absolute terms but also as a fraction of the total energy used. In the two most energy-intensive industries, primary metals and chemicals, electricity's share of total energy consumed nearly doubled between 1962 and 1980. Only in the manufacture of transportation equipment does electricity use stay proportionally about the same in this period. The bars represent purchased energy alone; they neglect the considerable energy produced within such industries as petroleum and paper. Electricity consumption is represented in terms of the primary energy (largely from coal and oil) needed to produce it, assuming an equivalence of 10^4 Btu/kWh.



bread can be baked twice as fast by microwave—15 minutes versus 30 in a conventional oven.

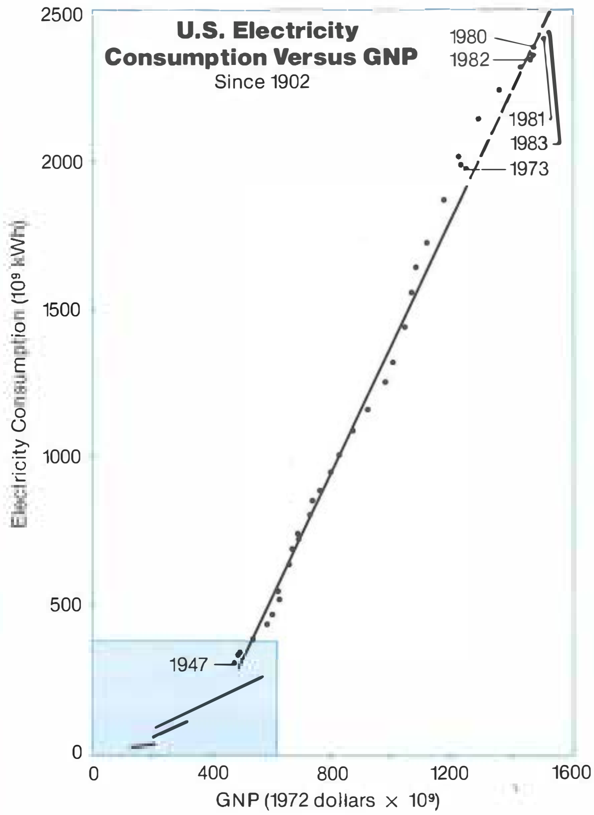
But there is another dimension even beyond that of adopting electrotechnologies that substitute for other combinations of energy and method. Chauncey Starr, EPRI's founding president and now director of its Energy Study Center, observes that "utilities are moving toward considering not only the generation and distribution of electricity as their responsibility but also its efficient end use." Calling to mind the image of computers as thinking machines, Starr says, "The combination of new 'mental processes' adapted from information technology and new physical processes—mostly electricity-based—can create major improvements in industrial productivity."

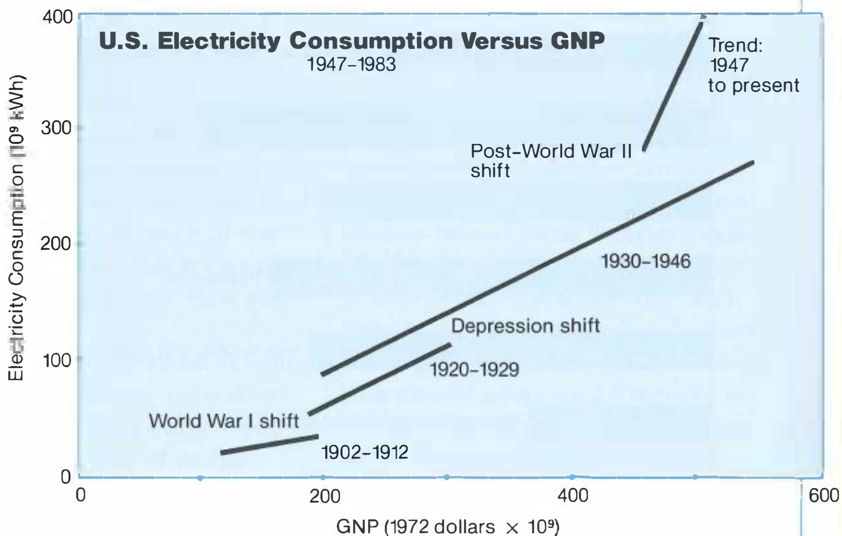
On this basis, today's revolution is like the introduction of electric unit drives all over again. Motors producing mechanical energy at the point of use leveraged every other factor of production in the already mechanized industry of the 1920s. Computer control today is similarly promising to boost the productivity of almost any industrial operation, especially those that are already electric. And the new attribute, the new aspect of form value, more than any heat or muscle, is the rapid communication and programmable control involved. Small wonder that people speak of electronification as they once spoke of electrification.

Trends and applications

Statistical snapshots of U.S. energy use at two times in the 1970s mark the trend to electricity and underscore the idea that electricity is more than just another form of fuel. If anything, the trend was accentuated during those years by the energy crisis—the oil embargo, the sudden increase in oil prices, and the unusually cold winter of 1976–1977. Individuals and institutions, families and factories cut back on all energy use, but one way they cut back

Data compiled and analyzed by EPRI's Energy Study Center demonstrate the consistency of the historical relationship between electricity consumption and GNP. Over the last 82 years there have been four distinct periods, each lasting longer than the preceding period, as electricity pervaded ever-wider ranges of economic activity. Progressively steeper slopes in the plotted relationship indicate more-intensive electricity use in each successive period. The longest single relationship has been the last 37 years of the post-World War II era, which is expected to hold up despite the large dislocations brought about by the energy crisis.





on other forms was by switching to electricity. Between 1973 and 1979 residential and commercial electricity consumption (combined) increased 19%, and industrial use increased 22%. By contrast, nonelectric energy use in the same sectors fell 4% and 8%, respectively.

The trend was more pronounced in several individual industrial categories, particularly where electricity had been a minor fraction of energy consumption. Although clearly documenting greater use of electricity, the record does not in all cases signal a larger electricity fraction among all energy forms. Thus, between 1972 and 1980, Census Bureau data for the petroleum industry show a 27.5% increase in electric energy use. Increases for other industries during that period were machinery (except electrical), 25.4%; paper, 18.1%; food, 16.8%; primary metals (mostly steel and aluminum), 12.9%; stone and refractory materials, 10.5%; and chemicals, 8.6%.

Manufacturing uses of energy are far from simple to categorize. Operations and processes are highly varied, and technologies are numerous to a degree that defies accounting. In addition, the economic contexts are almost endless because energy cost is normally treated as part of the product cost rather than as company overhead.

EPRI has found it revealing, however, to organize all the functions of electricity in manufacturing under just four basic headings. Thus, the 1980 total usage of 716.9 billion (10^9) kWh compiled in the Census Bureau's *Annual Survey of Manufactures* was divided among motors (451.8 billion kWh), process heat (65.4), electrolytics (103.1), and lighting and space conditioning (96.6).

Motor drives are clearly the dominant application of electricity; in fact, electricity is almost the only power mode for pumps, conveyors, fans, and compressors, as well as the spectrum of crushing, grinding, stamping, trimming, mixing, cutting, and milling operations that pervade manufacturing.

Process heat, on the other hand, is an application where electricity has scarcely scratched the surface. All manner of thermal processes are used to cook, soften, melt, distill, anneal, and fuse materials and products. But electricity so far provides only 3% of that heat.

Electrolytics is uniquely electric, the gamut of electrochemical processes used to separate, reduce, and refine metals and chemicals, as well as to create finishes of many kinds of metal surfaces.

Lighting is completely electric, space conditioning far less so. Both functions are pervasive and can be relevant to the productivity of specific industries, technologies, or processes. Generally, however, they are considered to be overhead items, and their advanced efficiencies are separate R&D pursuits, to the potential advantage of all sectors of electricity use.

In addition to these basic categories, however, flexible and automated manufacturing operations are becoming a fifth application because of the common thread and rapid ascendancy of computer aid and controls. Special note can also be made of the innovative ways that various chemical, petroleum, and food processors are beginning to use electrically produced mechanical energy, usually in the form of motor-driven centrifuges and vacuum pumps, to take the place of thermal energy (distillation) to separate materials.

Motors and drives

Motors represent some 63% of all 1980 electricity use in manufacturing, and much of this use and its cost can be allocated to specific operations and processes. Motors themselves, however, constitute a fairly well defined technology, amenable to improvement apart from their application contexts.

Speed control of motor-driven machinery, for example, has ramifications for electricity consumption, regardless of the machinery use. But mechanical and hydraulic adjustable-speed drives (ASDs) tend to be expensive, inefficient, and limited in their own controllability. The alternative, for fan and pump applications in particular, has been mechanical dampers or valves that meter fluid flow while constant-speed motors run on, wasting both electricity and some fraction of their own operating lifetimes.

Electronic ASDs are now making inroads throughout industry (including electric utilities themselves), catching on because they cut energy requirements by as much as 50% in some applications and because unlike hydraulic clutches, for example, they are compact and easily retrofitted in tight spots. A measure of the importance of ASDs is the projection of their use of electricity in the process industries, such as chemicals, food, paper, petroleum, textiles, and lumber.

From an estimated 21 billion (10^9) kWh in 1980, ASDs are estimated to represent some 387 billion kWh by the turn of the century, a figure greater than all electricity uses in the process industries today. This skyrocketing use of electricity does not mark a growth in motor-powered plant functions as much as it emphasizes the expanded use of a unique energy-saving mechanism, one that scores points for extended equipment life and reliability as well.

Process heat and control

Heat of some quality level defined by temperature is a major application of energy in 10 groups of manufacturing industries. But on a Btu basis alone, electricity has not been cost-competitive with fossil fuels, especially in the largest, most energy-intensive operations, those of the metals and chemicals industries. Electrotechnologies that can apply and control heat in special or precise ways are necessary for gaining an advantage in productivity.

Of the 65 billion (10^9) kWh used annually for process heat, over half is used by the primary materials industries, the producers of iron, steel, and aluminum, and stone, clay, and glass. During the 18 years from 1962 to 1980 these industries built their total energy use by only 15%, but they approximately doubled their electricity use by the widespread adoption of direct arc melting, direct resistance melting, and induction melting.

Perhaps the best-known of these electrotechnologies is the electric arc furnace used in steelmaking. It melts its charge by the heat of an arc between two electrodes that are lowered gradually into the furnace. Arc furnaces today produce about 30% of annual domestic steel tonnage, up from less than 10% a little more than 20 years ago. Able to accept 100% scrap metal as a feedstock, which avoids the capital and energy outlay of blast furnaces to reduce iron ore, arc furnaces are cost-effective at capacities as low as 25 tons, a rare economy of small scale.

But the technology has been more than just a productivity improvement in otherwise traditional steelmaking. Arc furnaces have also pioneered a geographically dispersed industry of scrap-fed minimills that fill regional and local steel needs. About 30% of all steel industry electricity use today is by arc furnaces; and as minimills continue to be built, limited only by available scrap stocks, that electricity share is projected to exceed 40%.

The success of arc furnaces and minimills is more than someone's R&D tour de force. An industry must have a good market growth prospect or a large margin of energy use for electricity substitution. To discern such opportunities requires looking at the manufacturing uses of energy from various viewpoints. "We have a tremendous job simply coming to understand the uses of energy in manufacturing," says Thomas Schneider, director of EPRI's Energy Utilization and Conservation Technology Department. "In process heating alone, for instance, you have to know what is being heated, why, and how much, because the ability to substitute electricity productively, profitably, depends very much on the specifics of the process."

Among the lessons, according to Schneider, is to look for heating tasks that require very high temperatures, such as metal production. Alternatively, he suggests applications that involve high-value products, such as food, or where there is a touchy technical problem, such as the precision heat control needed to vulcanize rubber products.

At least four groups of metal fabrication industries (transportation equipment, machinery, electrical equipment, and metal products) use heat in a variety of forming, bonding, finishing, and coating operations. Electrotechnologies here consumed nearly 26 billion (10^9) kWh in 1980, with induction heating alone accounting for almost 22 billion kWh.

By the turn of the century, with industry growth and continued electricity substitution, induction heating may well use more than 53 billion (10^9) kWh; but that figure will represent a much smaller proportion of total electricity use in metals fabrication. This projected change in the mix reflects dramatic growth in flexible manufacturing, largely the use of robots and computer aids for enhanced automation. Electricity requirements for this purpose are foreseen to expand from less than 0.1 billion kWh four years ago to about 21 billion kWh annually by 2000.

The new avenues

The projection for flexible manufacturing clearly states an expectation of what electrification will do for productivity in machinery, vehicles, electrical equipment, and an endless list of other metal products. It explains why laser processing and robotics are two of the comers among electrotechnologies. Lasers are easily seen for their energy consumption in cutting, drilling, fusing, and scribing various materials, as well as for annealing or hardening metals; robotics may also entail heavy power use for welding or manipulating large components. But the wide-open future is more a result of today's and tomorrow's capabilities in computer-programmed guidance.

Robots are exciting, even awesome in some of the images they bring to mind. But mostly they are simply one part of a much larger context known as computer-aided design and manufacture, now taking on a new reality with the advent of microprocessors. The combination of reprogrammable controls and movable tooling introduces flexibility and fast change into manufacturing operations that formerly required long runs to justify each labor-intensive setup of rigid jigs and fixtures.

Harry tells the story of Peerless Saw Co., a small Ohio manufacturer of circular saw blades, and how it turned its fortunes around by replacing manually operated punch presses with a computer-guided laser cutting system. The most spectacular measure of the new productivity is a sixfold reduction of the average time to produce a saw blade: from 90 minutes to 15. Setup time is negligible, enabling Peerless to reschedule, interrupt production runs, and reduce the premium for one-of-a-kind blades.

"The software for this system enables Peerless salesmen to design new custom blades on the spot, just from a few specifications over the phone," reports Harry. "What's more, the computer memory holds 4000 blade designs, so there's no inventory of punch-press dies to shelve, sharpen, and eventually replace."

Electricity is also changing the shape and thereby the productivity of process-related operations. Together, the chemical, food, textile, petroleum, and a few other industries use half of all manufacturing electricity each year. For the chemical industry alone the total in 1980 was 145 billion (10^9) kWh.

Schneider says the stage is set for

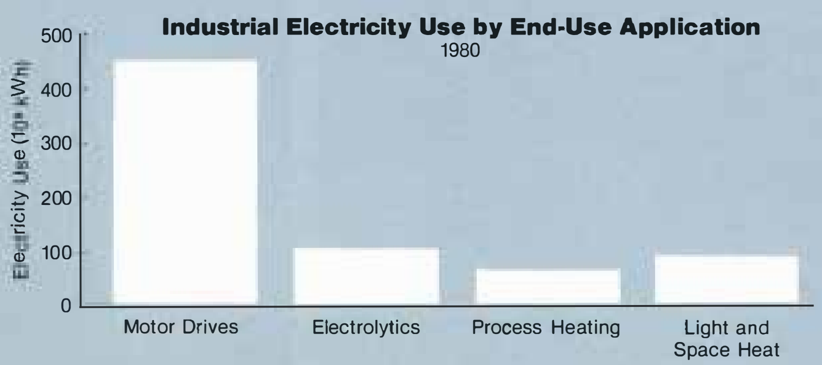
Electricity use in industry can be conveniently broken into four areas of end-use application. Motor drives account for over 60% of the electricity used by American industry, principally for the continuous movement of materials and compounds through a vast range of industrial processes. Electrolytic applications are highly concentrated in the aluminum and chemical industries. Process heating, particularly in the primary metals and fabricated metals industries, is the area of greatest opportunity for new electrotechnologies.

ELECTRICITY USE BY INDUSTRIAL SECTOR

1980 (10^9 kWh)

Industrial Sector	Total Electricity Use	End-Use Application: Motor Drives	Electrolytics	Process Heating	Light and Space Heat
Process-related industries					
Chemicals	145.0	96.9	31.7	0.4	16.0
Paper products	76.0	61.6	—	—	14.4
Food products	43.3	35.1	—	2.7	5.5
Petroleum and coal products	37.7	31.3	—	—	6.4
Textile mill products	26.1	20.6	—	0.5	5.0
Rubber and plastics	21.9	19.0	—	—	2.9
Lumber and wood products	14.8	11.0	—	0.5	3.3
Printing and publishing	9.7	7.1	—	—	2.6
Apparel	6.0	4.4	—	—	1.6
Subtotal	380.5	287.0	31.7	4.1	57.7
Fabricated metals industries					
Machinery (nonelectric)	30.7	20.9	0.1	8.8	0.9
Transportation equipment	30.0	22.8	—	3.2	4.0
Electrical equipment	27.2	22.5	—	0.5	4.2
Fabricated metal products	25.3	10.9	—	13.2	1.2
Instruments	6.0	4.2	—	—	1.8
Miscellaneous manufacturing	3.6	2.5	—	—	1.1
Subtotal	122.8	83.8	0.1	25.7	13.2
Primary metals industry	175.4	50.9	71.3	33.2	20.0
Stone, clay, and glass products	30.8	24.7	—	2.4	3.7
Other	7.4	5.4	—	—	2.0
Total	716.9	451.8	103.1	65.4	96.6

Sources: U.S. Bureau of the Census, *1980 Annual Survey of Manufactures*, and estimates by Resource Dynamics.



greater electrification. "We're seeing ways that electricity can displace fossil fuel process heat—not just replace the fuel but do away with the need for heat by doing mechanical work instead."

Freeze crystallization, for example, illustrates how mechanical energy can take the place of thermal energy for separating materials. Alan Karp, a project manager in the Industrial Program, explains that although the feasibility of freeze crystallization has been established for only a few processes, the inherent advantage in thermodynamic efficiency is clearcut because only about one-half to one-tenth as much energy is required to freeze a liquid as to vaporize it. The process typically uses an electric motor–driven refrigeration cycle to solidify liquid fractions at successively lower temperatures, whereas conventional distillation boils them off at successively higher temperatures.

Membrane processes (notably, reverse osmosis and ultrafiltration) also illustrate the potential to displace thermal with mechanical energy. Here, motor-driven pumps create the necessary pressure under which semipermeable membranes separate liquid components. Because there is no change of phase (as in evaporation, for example), these processes are inherently energy-efficient. Once relegated to a few important but narrow applications, such as desalination, membrane processes are increasingly taking the place of evaporation in various tasks of the food, textile, and other process industries.

Electrolytic efficiency

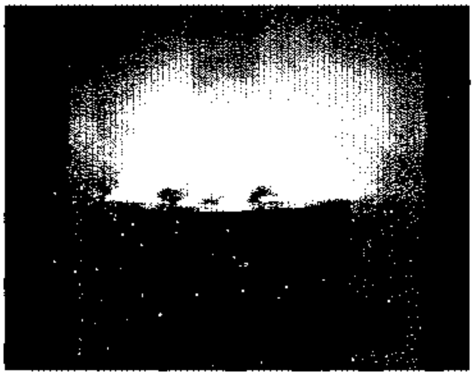
Of all the electrolytic processes, the production of aluminum is undeniably most important. In fact, the U.S. aluminum industry, the biggest in the world, accounts for about 12% of all electricity use in U.S. manufacturing, and 90% of that is for the potlines (smelters) that reduce alumina to primary aluminum. Although ranking far behind blast furnaces and steel mills in overall energy consumption, aluminum production uses about half again as much electricity.

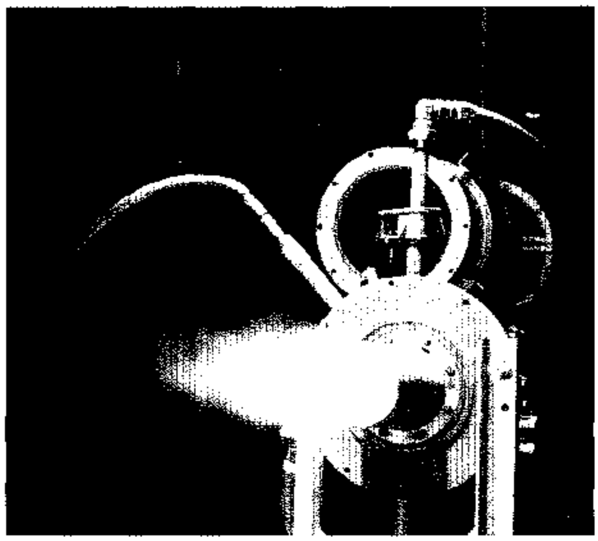
Because of this pivotal role of electricity, most aluminum smelters have been built in regions of historically cheap electric power. On average, however, electricity has gone from 19% to 25% of the variable cost of aluminum production in the last dozen years, and in the Pacific Northwest, to more than 30%. Because of power costs, new aluminum production facilities are likely to be built outside the United States.

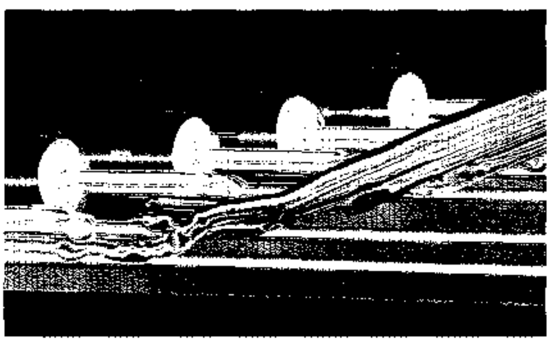
In general, the aluminum industry and its technologies are mature. Worldwide aluminum demand growth is slow, having just recovered from a brief downturn. There is excess capacity, plants are able to open and close in response to business cycles (and the level of electricity rates). But smelting productivity must improve if the U.S. industry is not to decline. Ingenuity can bring about an Indian summer, a lengthening of the competitive lifetime of domestic aluminum production.

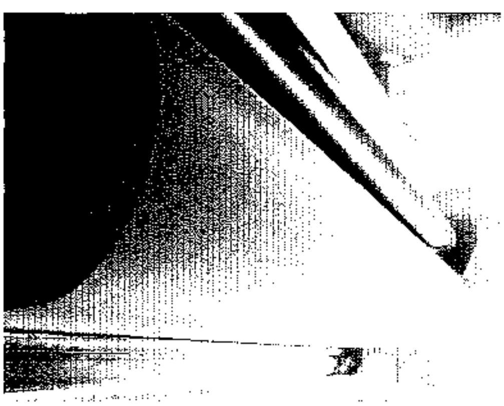
Aluminum Co. of America has demonstrated a totally new process, said to reduce electricity requirements by at least 25%, from today's best of 6 kWh/lb (13.3 kWh/kg) to about 4.5 kWh/lb (9.9 kWh/kg). But the need is for retro-

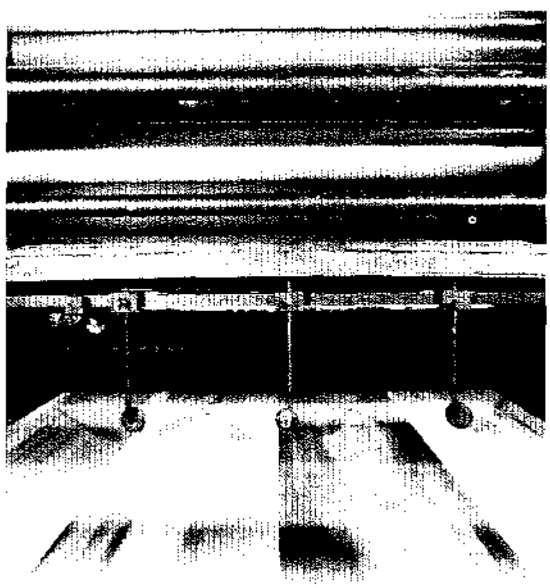
The future of American industry is tied to ever-increasing gains in productivity, offered in part by electrotechnologies and computer-controlled operations.











fittable measures, such as the modest electricity conservation step sought by Bonneville Power Administration (BPA) with a special coating for the graphite cathode of an aluminum smelting pot. Because molten aluminum does not thoroughly wet the graphite, so to speak, extra voltage is needed simply to overcome an incrementally increased resistance. A titanium diboride coating presents no such barrier, and the hoped-for energy saving may be 2%. The fraction is small, but in an already large block of energy it represents an important cost increment for utilities and aluminum producers alike.

Less modest is the anticipated effect of a DOE-funded noncombustible anode (to be used in conjunction with BPA's cathode coating). Because the new anode is not gradually destroyed by electrolytic action, its geometry and gap spacing can be optimized and controlled, effecting a cut in electricity requirements of as much as 35%. Seen another way, in terms of aluminum output per kWh of electricity, success in this development will mean a potential productivity increase of more than 50%.

Technology marketing

The end-use R&D sponsored by DOE and BPA, like that sponsored by other electric utilities and EPRI, can be seen in at least two ways. In the context of overall U.S. economic health, revitalizing industrial productivity is a public service; it is a matter of the national interest. In the context of individual utility operations, it is business development, perhaps preservation, by means of new technology. In short, it is industrial marketing.

The move comes none too soon. A long and lulling tradition established electricity as a commodity—kilowatthours turned out by generators, poured into transmission lines, metered at the point of delivery, and valved on or off with a switch. Most R&D dealing with electricity itself has been to improve the purity and uniformity of the product, cut down friction and surges in the line, and strive for steady flow and pressure at the meter.

Today's inquiries into electricity end uses have far-reaching value for utilities. At the very least, the inquiries yield some foreknowledge of demand trends in service territories, invaluable for utility planning during times that still must be called uncertain. At most, end-use research yields technology options that may influence demand trends within the larger context of business and regulatory needs.

Harry sees a utility's industrial electricity customers as a portfolio of users who can be helped in different ways because of their different objectives. "How does the customer use electricity now?" Harry asks. "You've got to know the customer in order to know and provide what is most needed and beneficial." Karp, Harry's associate, echoes the point. "Customers aren't sitting still," he says; "they're doing their own technology evaluations, and they will make their own decisions on electricity use.

Karp's observation emphatically counters the idea that a utility can use its electrotechnology marketing to oversell its market. "Companies are alert to their own industries' energy-use patterns and practices. They're not about to buy electricity for its own sake." But Karp acknowledges Harry's point that a utility, from its increasing familiarity with a wide variety of electrotechnologies, can selectively direct attention to those that accelerate or retard its overall load growth and improve load factor (the ratio of average to peak load).

Load growth is not a uniform goal of electric utilities, either in their own judgment or in the public perception expressed by regulatory bodies. Population growth and, in the long run, productivity growth gradually build load, of course. "But in the short run," comments Schneider, "regional and local circumstances have a lot to say about the desirability of new utility load and the generating capacity to meet it."

Some utilities, in Schneider's opinion, are progrowth for themselves but acknowledge the larger reality that new capacity at today's capital costs could have a damping effect in their regions by requiring higher rates. "Those utilities have to aim their technology marketing at conservation measures, at making the very best use of present generating capacity."

Other utilities also favor electricity conservation that defers capacity growth, but for the different or added reason of their own financial circumstances. These are utilities severely shaken by the recession and not yet ready to take on new capital outlays.

But fully half of utilities, Schneider thinks it safe to say, are prepared to serve more load and can work aggressively with their customers who need to travel that avenue to better productivity.

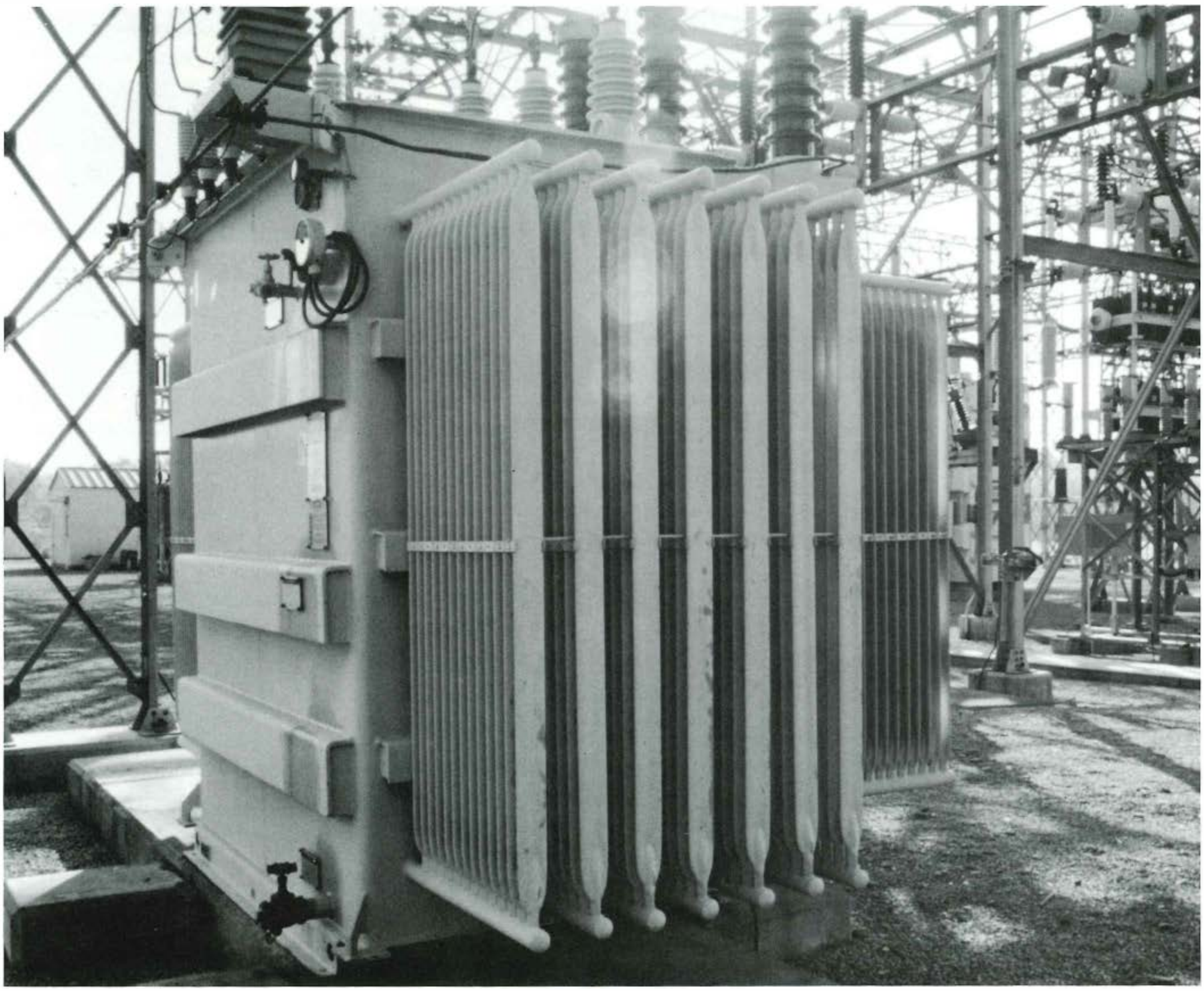
The important outcome remains that individual utilities and their customers gain control of their own destinies. Better productivity is key to that objective. And development of new electrotechnologies can help.

Harry's enthusiasm shows when he envisions the role of computers and telecommunications in setting the pace for new electrification. He suggests that many electrotechnologies have been waiting in the wings up to now or have penetrated only a few industries and markets because technologies and processes were compared on the basis of energy cost alone for many years, and the overall productivity leverage of electrification was not apparent. Industries are alert today, however, and electric utilities are joining them, through EPRI, in exploring the new potential for electrification. ■

This article was written by Ralph Whitaker. Technical background information was provided by Thomas Schneider, Leslie Harry, and Alan Karp, Energy Management and Utilization Division; and by Sam Schurr and Milton Searl, Energy Study Center.

New Transformers: Nontoxic, Nonflammable

Rejection of PCB liquids motivated the development of new dielectric and coolant media that compete with conventional transformer oil in performance, safety, and cost.



For many years fire resistance has been an increasing requirement in transformer design. The reason is that more frequently transformers must be sited in or near buildings, where they are exposed to the risk of fire. The oil traditionally used as a transformer coolant and dielectric is itself flammable, clearly an additional danger if a transformer tank should give way in a fire.

Also a concern is some statistical incidence of internal transformer failure—arcing caused by an electrical fault. In some instances, a small arc is quenched by the coolant oil. But an arc can generate explosive gas in the oil—gas that may rupture the tank and then explode, thereby igniting the oil also released.

Circuit breakers, in conjunction with high-speed relays and fuses, help to minimize the effects of faults in transformers; and firewalls, berms, and curbs are often constructed for additional protection from spilled oil. This sort of construction, however, is expensive and difficult to apply in many indoor installations where space constraints dictate compactness. Moreover, there is the cost burden of fire insurance premiums scaled to the extra risk. The more-direct solution is to use transformer fluids that will not burn.

Candidates over the years included air, nonflammable gases, and synthetic liquids, such as silicones and polychlorinated biphenyls (PCBs). Utilities found most of these to be too costly—either by themselves or in their ultimate effect on transformer size and performance. Despite a cost premium of about 40%, however, commercial and industrial builders widely adopted PCB transformer designs for use inside buildings; and, to be sure, utilities also had increasing occasion to use them.

PCBs thus seemed to be the ideal dielectric and coolant for transformers where fire safety was paramount. Then, in the early 1970s, PCBs were declared to be an environmental hazard and their use was severely restricted by the federal government.

With PCBs effectively banned, the search for a new fire-resistant fluid and transformer design became a pressing one. EPRI took on the responsibility in 1976, joined by the Empire State Electric Energy Research Corp. and Niagara Mohawk Power Corp. Together they funded a cost-shared project with Westinghouse Electric Corp. to develop transformers having the fire safety and dielectric performance obtained with PCBs but at the cost of oil-filled units.

Research and development

Various liquid and gaseous coolants were investigated for their dielectric and thermal properties, as well as for their compatibility with transformer materials, but the phenomenon of two-phase cooling showed special promise.

Two-phase cooling is based on the fact that a substance undergoing a change of phase can absorb relatively large amounts of heat without temperature increase. As it vaporizes, a liquid coolant performs more efficiently than a liquid or a vapor alone. This principle was applied in two distinctive transformer designs.

The first of these uses a pump to circulate a small volume of fluorocarbon liquid coolant (such as Freon). Having a low boiling point, the coolant vaporizes on contact with the transformer coils and core. Thereafter circulated as a vapor through the coolers, it is eventually condensed and drained into a sump for recirculation. A 15-kV, 2500-kVA prototype of this design was built and tested.

This transformer is intentionally liquid-poor, and at startup its internal temperature is not sufficient to vaporize the coolant. A noncondensable gas (SF_6) therefore fills the tank for dielectric protection at startup. Then, as the temperature of the working transformer increases, the noncondensable gas, lighter than the now-vaporizing fluorocarbon, rises above the coil and core so that the fluorocarbon becomes the primary medium for insulating and cooling.

The second design is a liquid-filled transformer, its core and coil assembly immersed in a 3:1 mixture of perchloroethylene (C_2Cl_4) and oil. The oil lowers both the freezing point and the cost of the coolant, while retaining the fire resistance of the C_2Cl_4. Because C_2Cl_4 boils in the 125–150°C range, depending on the pressure in the transformer, it vaporizes at hot spots but immediately condenses in the surrounding liquid, an effective self-limit on hot-spot temperatures. Lower operating temperature is thus an added benefit of this kind of two-phase cooling system. Two prototype units were built, a 34.5-kV, 1000-kVA network unit and a 34.5-kV, 5000-kVA substation unit.

Manufacturing and application

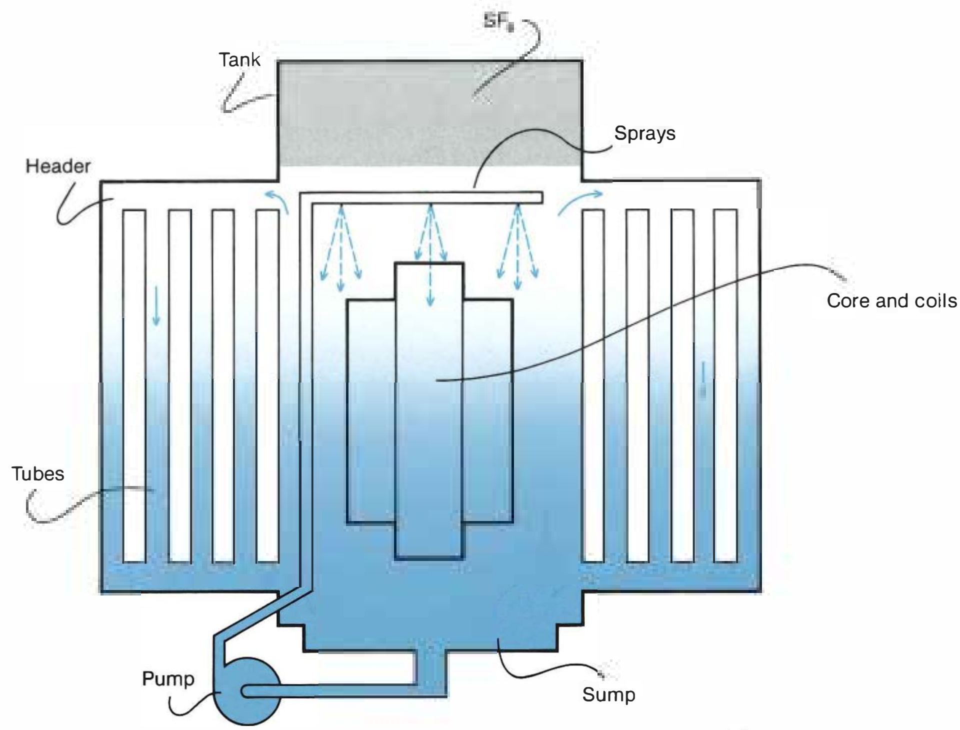
By 1982, after six years of R&D involving nearly $2 million, EPRI and Westinghouse had transformer designs and prototypes with fire resistance equal to or better than that achieved with PCBs.

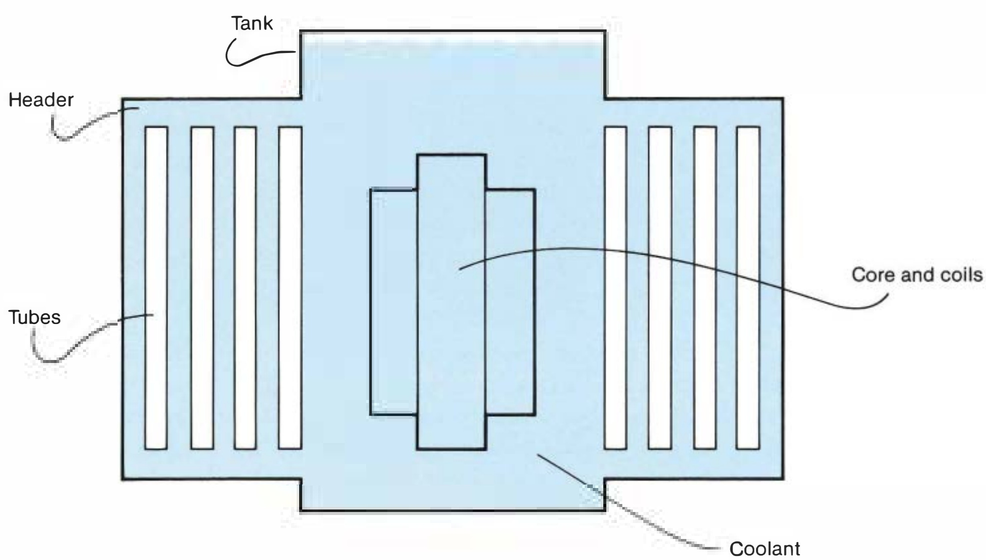
Affordability also was one of the criteria, and the EPRI goal of staying within the cost range of comparable oil-filled transformers was very nearly met—118% for the gas-vapor system and 103% for the liquid-filled design. The latter gained a cost advantage at least partly because it requires no pumps. Both designs were significantly lower in cost than the next best alternative, a silicone-based design costing about 145% of the oil-filled reference transformer.

The new units are essentially unchanged in shape and size from previous designs, so they are compatible in the normal course of transformer replacement. But it is important to note two reasons that the C_2Cl_4-oil mixture is not retrofittable in old transformer tanks. First, for the sake of environmental acceptability, the C_2Cl_4 constituent must be manufactured to essentially 100% purity. Second, although harmless to cellulose (paper) insulation, both C_2Cl_4 and SF_6 may attack other transformer components, such as gaskets, resin-bonded materials, and adhesives, that are compatible with oil and PCBs.

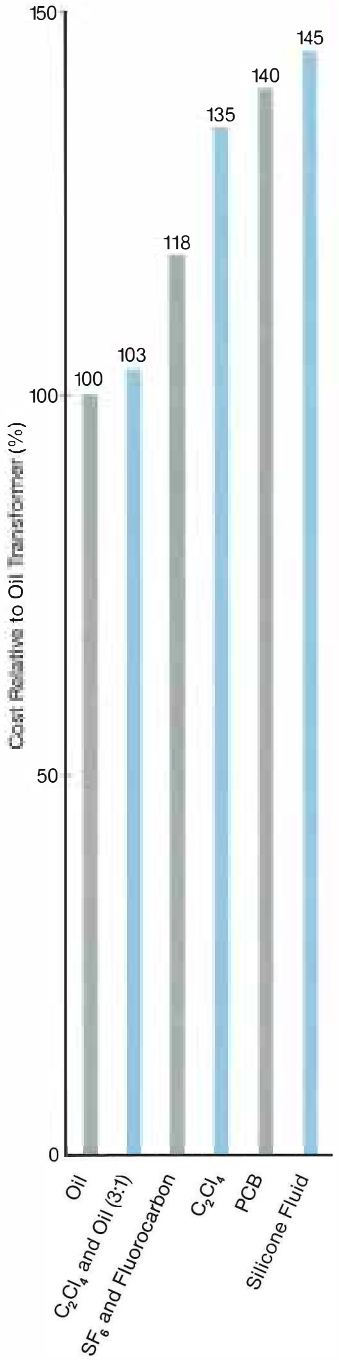
The new fire-resistant transformers have been proving themselves during re-

Two-phase cooling is at the heart of two new transformer designs. In one a liquid fluorocarbon coolant is sprayed over the unit's core and coils, which give up heat by vaporizing the fluorocarbon. As it travels through the cooling tubes, the vapor is condensed back to liquid form and is recirculated. SF_6, a noncondensable gas that cools the transformer during startup, is pushed up into a holding tank as the heavier fluorocarbon vapor rises in the unit. In another design a 3:1 coolant mixture of perchloroethylene and oil remains primarily in liquid form, vaporizing only at hot spots in the transformer. This liquid-filled transformer is smaller and less expensive than the fluorocarbon design.





Both the C_2Cl_4 and SF_6-fluorocarbon transformers cost less than the PCB units they were designed to replace. In fact, the C_2Cl_4-oil design is only 3% more expensive than the standard oil-filled utility transformer.



cent years. The 34.5-kV, 1000-kVA liquid-filled network prototype was tested by Niagara Mohawk, and the 34.5-kV, 5000-kVA substation prototype, by Pennsylvania Electric Co. In addition, Consolidated Edison Co. of New York, Inc. (Con Edison) installed three 6000-kVA gas-vapor units at its Ravenswood generating station.

As a follow-up to its work under EPRI auspices, Westinghouse set out to commercialize the liquid-filled design, adapting it for the company's small power transformers (112.5–10,000 kVA). The initial specification was for pure C_2Cl_4 as the coolant, which was considered necessary for full fire resistance despite its cost premium of about 35% (relative to oil). However, additional testing under insurance industry laboratory auspices is expected to confirm that the originally developed C_2Cl_4-oil mixture is nonflammable. Because it is also less expensive, it should show up in the commercial units.

One of the first users of the liquid-filled fire-resistant transformers is Kansas Power & Light Co. The utility bought four units rated 1500 kVA to work in conjunction with boiler circulating-water pumps and 16 units rated 1000 kVA for substation use. KP&L estimates a saving of about $55,000 over a five-year period, compared with the cost of silicon-based units.

Westinghouse fire-resistant transformers are now available in ratings of up to 15-kV primary and 5-kV secondary, 112.5–10,000 kVA. More than 50 units have been bought by utilities, and more than 400 have been bought for various industrial applications.

Ongoing work

Encouraged by the technical and commercial success of the small power transformer R&D, EPRI initiated two similar projects for fire-resistant designs in the 138-kV, 50-MVA class.

General Electric Co. investigated gas-vapor cooling with liquid trichlorotrifluoroethane ($C_2Cl_3F_3$, or Freon 113), which boils at 47°C, thus providing two-phase cooling during the normal operation of the transformer. This design, however, did not meet the cost objectives of the project.

Westinghouse continued with its liquid-filled configuration, again using a 3:1 C_2Cl_4-oil mixture. But the new transformer design pointedly calls for normal operation below the coolant boiling point, avoiding even the localized (hot-spot) boiling that occasionally occurs in distribution units under overload conditions. The reason is that such nucleate boiling on the surface of conductors degrades the overall dielectric strength of an insulation system, forcing a reduction in rating that is uneconomic in large power-class transformers.

A unit of one full-scale transformer phase has been built and tested. Costs appear to be in line, and a 138-kV, 65-MVA prototype is being built for installation on the Con Edison system. The final results of testing should be available from EPRI in 1985.

The overall R&D results now coming into commercial use are rewarding indeed. Although PCB-filled transformers made headlines as an environmental and health hazard, they were never more than a small minority—perhaps 5%—of the units operated by U.S. utilities on their own systems. Oil remains the conventional dielectric and coolant for the majority of transformers sited outdoors, where fire is not a major potential problem. And for this reason, oil-filled designs must be the cost basis for comparing the products of EPRI-sponsored research.

Today, instead of the fire resistance of PCBs at a cost premium of 40% (affordable only in special-purpose applications), the same fire resistance is becoming available at a modest cost premium that should prove affordable for routine use in all power-class transformer ratings. ■

This article was written by Stephen Tracy, science writer. Technical background information was provided by Robert Tackaberry and Edward Norton, Electrical Systems Division.

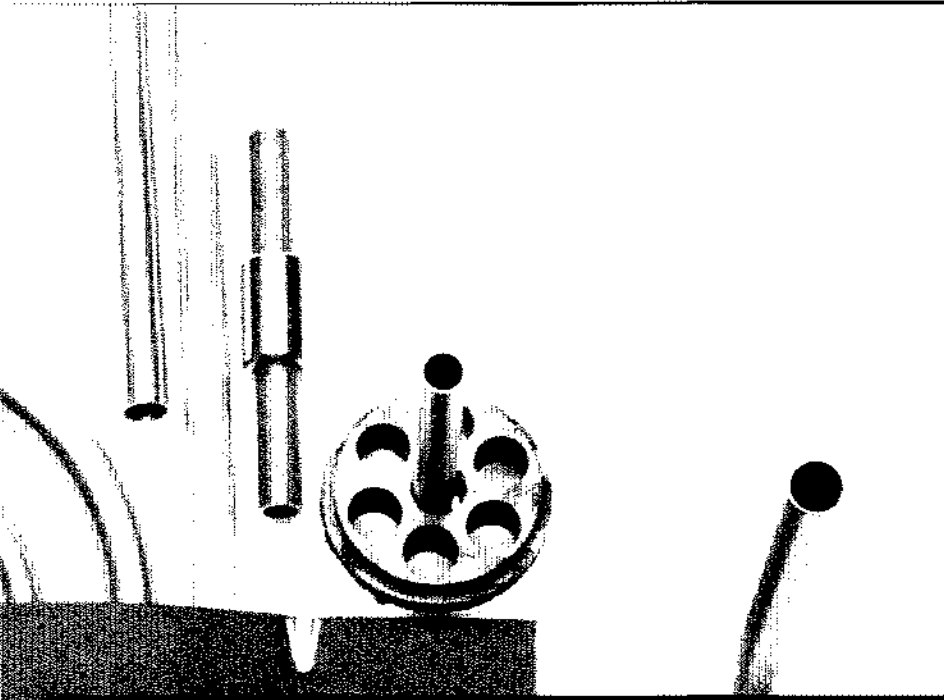
Longer Life for Steam Generators

As its name implies, a pressurized water reactor (PWR) avoids formation of steam inside its primary cooling system by keeping water under high pressure so that boiling does not occur. However, steam is needed to drive a power plant's turbines, so a steam generator takes heat from the primary system and uses it to boil water in the secondary water system. Among other advantages, this arrangement keeps radioactive contaminants inside the closed primary loop, away from the turbines.

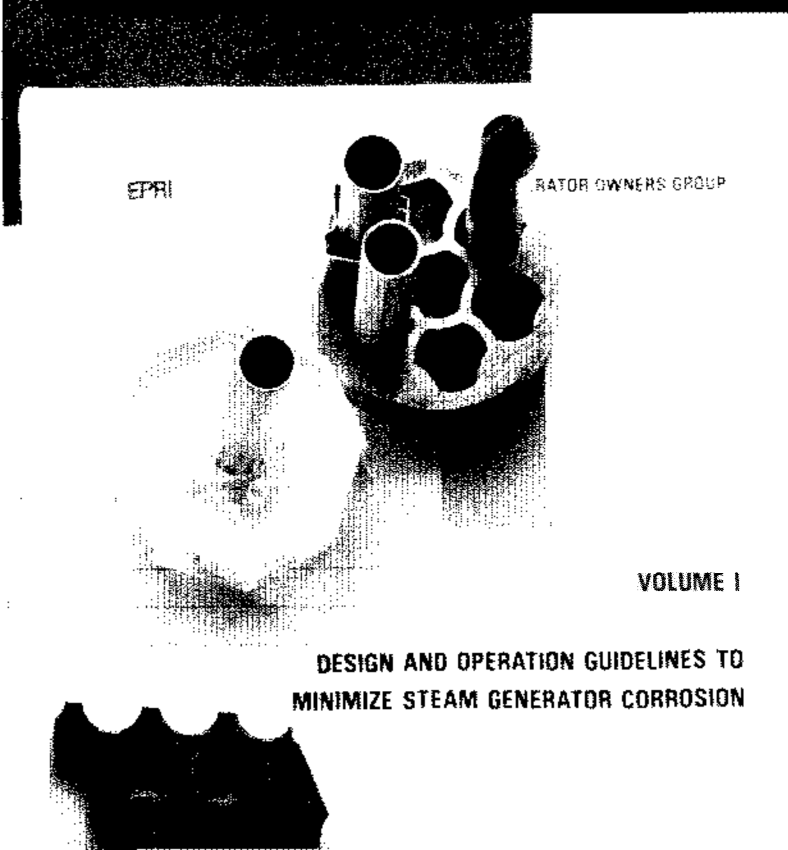
The main disadvantage is that steam generators are expensive components that have proved less reliable than originally anticipated. Experience shows that more than two-thirds of PWR plants have now had corrosion or mechanical damage in their steam generators. There are about 100 operating PWR power plants, of which about 20 have operated for more than 10 years. Although they were expected to last up to 30–40 years, 17 steam generators at 6 power plants have had to be replaced before 10 years, at a cost of $200–$400 million per plant.

To diagnose the causes of these problems and to identify potential solutions, the electric utility industry organized the first Steam Generator Owners Group (SGOG-I) in early 1977. The group included 24 U.S. utilities, plus 3 from Europe and a group representing Japanese utilities. The first five-year research plan sponsored by SGOG-I and managed by EPRI cost about $40 million and concentrated primarily on damage resulting from corrosion of steel support structures inside steam generators. This damage has now largely been controlled, thanks primarily to the application of operating guidelines developed as a result of SGOG-I research.

But in the meantime new damage forms—such as cracking, pitting, and wear of nickel alloy tubing in steam generators—became more visible. To meet this challenge a second owners group (SGOG-II with 32 members representing 45 utilities) was formed to fund another cycle of research under EPRI manage-



Eight years ago, corrosion and tube denting seriously threatened the reliability and design life of steam generators across the country. Concentrated research by the Steam Generator Owners Group diagnosed the causes and produced effective solutions, notably guidelines for water chemistry control in the secondary loop.



ment, beginning in 1983. Work on this anticipated four-year, $25 million program is now approaching its midpoint and has yielded some broad principles for addressing these more recent phenomena.

"The recommendations produced by SGOG-I research have proved very effective," says Stanley J. Green, director of the Steam Generator Project Office. "These recommendations can help utilities overcome many of the difficulties previously encountered and thus improve the availability and reliability of steam generators and extend their lifetime. At the same time, I believe we have also begun to identify possible solutions to the newer problems that have arisen, and we are now in the process of verifying these quantitatively."

A forest of tubing

A typical U.S. commercial PWR may have from two to four steam generators, depending on its size and manufacturer. Each steam generator consists of a forest of thousands of tall nickel alloy tubes (alloy 600 or alloy 800), each about 0.75 in (19 mm) diameter, that rise about 30 ft (9 m) inside a cylindrical steel vessel. Heat is transferred between the hotter water circulating inside the tubes and a separate water stream moving freely through the surrounding vessel. Unlike steam generators in conventional power plants, however, those used with a PWR produce steam by boiling the freely moving water on the outside of the tubes rather than inside the tubes. The water in the primary loop, coming from the reactor core, moves inside the tubes and does not boil because it is maintained at a much higher pressure. Keeping the lower-pressure steam-cycle water outside the tubes minimizes the thickness of the outer vessel walls and provides radiation shielding and an added safety margin.

The need for this arrangement creates some difficulties. There are many small crevices between the tubes and supporting structures inside the vessel that can trap and concentrate water impurities, which contribute to corrosion. Further, nuclear plant steam generators do not have a mud drum for the collection and removal of corrosion products as some boilers at conventional plants have. As a result, a layer of sludge several inches thick can build up on the bottom tubesheet, through which the tubes are connected to the primary coolant circuit. This sludge layer provides an ideal environment for corrosion.

One reason why corrosion was not expected to have such a significant effect is that the water used in both circuits of a steam generator is very pure. The concentration of impurities, such as chloride ions, allowed in ordinary tap water can be as high as several hundred parts per million (ppm). For the secondary water of a steam generator, however, the concentration is limited to a few tens of parts per billion (ppb), which ordinarily is sufficient to prevent corrosion. But plant operating experience has shown that ions may concentrate in crevices as much as 60,000-fold or more. Such ions increase the corrosivity of the water. The larger-than-anticipated concentration of impurities found in the crevices has led to one of the key findings of research so far: much lower levels of ions and dissolved oxygen in the steam generator water are required to prevent corrosion than was previously thought.

One of the principal sources of ionic impurities in the secondary water loop is the condenser, where steam is cooled after passing through a turbine. The design of a condenser is conceptually similar to that of a steam generator but with the heat exchange reversed. Cold water passing through many small tubes removes heat from steam condensing on the shell side of the vessel. This condensation creates a vacuum in the main part of the vessel that can draw the cooling water out through any tube leaks. Because the cooling water is not purified to the same extent as water in the secondary loop, such leaks can contaminate the water going back to the steam generator. Parts of the turbine system and feedwater system, as well as the condenser system, also operate under vacuum. Leaks in these components similarly draw in air. The air is a source of oxygen, which may also be quite corrosive when combined with other contaminants. Another source of impurities is the makeup water added to the secondary loop to maintain a constant volume.

Because quantitative data on the effects of these impurities were not available until recently, utilities had little incentive to prevent small condenser or air leaks or to install demineralizers to remove impurities. Also, chemical cleaning methods used in fossil fuel plants have not yet been adapted for PWR steam generators. By 1976, however, sufficient availability loss had been experienced to indicate substantial changes were needed in steam generator operation and possibly in design.

Two patterns of damage

There are two major designs for steam generators, and corrosion or mechanically induced damage has differed somewhat in each. In a recirculating steam generator, tubes are bent to form an inverted U, with primary water entering the tubes through holes in one side of the bottom tubesheet and leaving on the other. Secondary water is fed into the steam generator vessel near the top and flows downward along its shell through a partitioned area called the downcomer. It then moves inward across the tubesheet and rises through the forest of 3000–7000 tubes, boiling as it goes. At the very top of the vessel are moisture separators that allow steam to pass through on its way to a turbine, while recirculating the remaining water back into the downcomer.

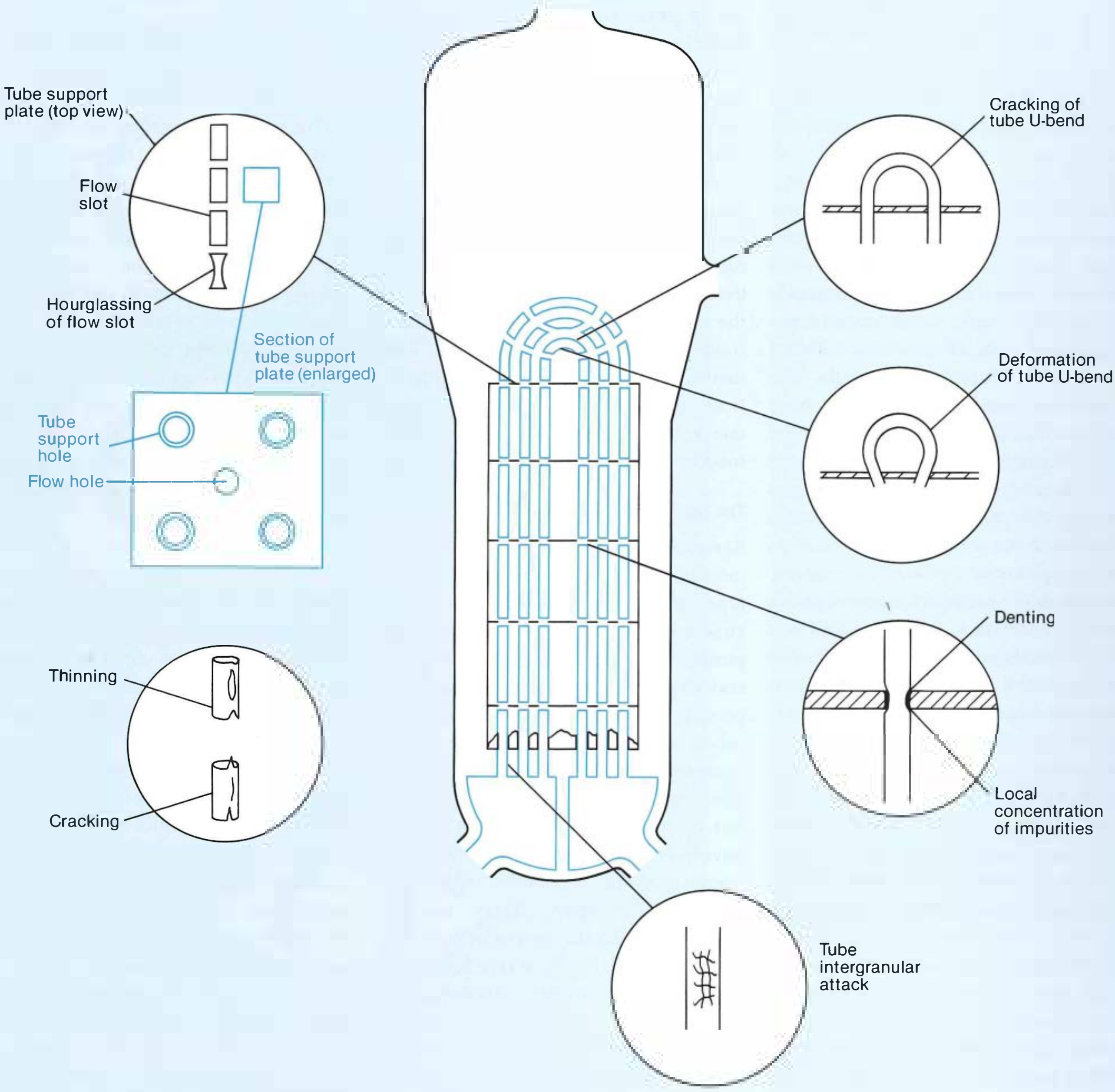
At first a few recirculating steam generators used a conventional all-volatile water treatment (AVT) adapted from fossil-fuel-fired boilers. At the first plants cooled by seawater, phosphate salts were added. Even before the formation of SGOG-I, however, this phosphate treatment was found to cause wastage, or corrosive thinning of tubes in the sludge region above the tubesheet. As long as a tube's surface remained constantly wet there was no thinning, but when sludge reached a critical height, layers were created in the sludge that were either dry all the time or alternately wet and dry. The parts of a tube exposed to the alternating wet-dry environment became quite susceptible to wastage caused by acidic phosphate compounds formed by reaction with the sludge.

Beginning in 1974 many utilities ceased adding phosphates and adopted the AVT system. This involved adding hydrazine to the water to scavenge dissolved oxygen and adding ammonia to control pH. Since AVT was widely adopted, wastage has ceased to be a major concern.

By the time SGOG-I was formed, the main difficulty facing owners of recirculating steam generators was denting, the constriction of tubes caused by corrosion of the carbon steel tube supports and tubesheet. This corrosion occurred because of impurity concentrations, especially acidic chlorides, in crevices between tubes and the surrounding supports. This denting restrained the flow of primary water through the affected tubes, but more significantly it also began to stress the tubes and supports mechanically, causing deformation and cracking.

In a once-through steam generator roughly 10,000 straight tubes run the entire height of a closed vessel. Again the primary water runs through the tubes, entering from the top and leaving from the bottom, while boiling takes place in secondary water circulating through the bulk of the vessel. The secondary water enters at mid-height and is directed down along the vessel walls by baffles. It then moves upward between the tubes and changes to superheated steam. The steam is directed back down along the walls from the top of the vessel to an outlet at mid-height. This pattern of circulation optimizes heat exchange and ensures steam superheat (none of the water

Two mechanisms of steam generator damage, tube denting and stress corrosion cracking, have drawn remedial attention from specially funded R&D programs managed by EPRI. Denting is a corrosion phenomenon traceable to impurities in the secondary loop. Stress corrosion cracking is influenced in part by water chemistry and also by stress levels and material composition.



GUIDELINES EARN TRANSFER AWARD

The Technology Transfer Award has been presented by EPRI's Nuclear Power Division to Peter F. Santoro of Northeast Utilities in recognition of his contribution to the development of new secondary water chemistry guidelines for steam generators. This marks the first time that such an achievement award, previously reserved for EPRI staff, has been given to a utility representative.

Santoro, who is director of Generation Projects at Northeast Utilities, recognized the importance of establishing appropriate water chemistry conditions in secondary systems and promoted the formation of SGOG's Water Chemistry Guidelines Committee. Published in 1982, the guidelines have now become widely accepted by the utility industry as a way to improve steam generator reliability at working nuclear plants.

According to a letter of commendation accompanying the award, Santoro aggressively took the lead in developing the guidelines and was most effective in securing SGOG acceptance of them.

The award was presented to Santoro by John J. Taylor, vice president, Nuclear Power Division, at the July 1984 semiannual meeting of the Steam Generator Owners Group. □

remains in a liquid state as it leaves the vessel).

Once-through steam generators have always used AVT, as well as condensate polishers to purify the feedwater, so wastage was never a concern. The problems affecting units with this design have tended to be mechanical in origin, although corrosion has also caused some damage. Cracking has affected tubes in the upper regions of once-through steam generators. This cracking is believed to be caused by the combined effects of a corrosive environment and small amplitude vibrations of the tubing resulting from high-velocity steam in the region. Called corrosion fatigue cracking, this problem apparently results from concentration of impurities around the upper tubesheet. Laboratory studies indicate that sulfur compounds, perhaps from the chemicals used to treat condenser cooling water, may be responsible. Some denting of tubes has also been inferred from abnormal eddy-current measurements, called dings, in regions where tubes pass through other support plates.

The SGOG-I response

Research sponsored by SGOG-I indicated that the corrosion affecting both types of steam generators could best be attacked by taking steps to ensure water purity, fostering the design of steam generators more resistant to corrosion, improving nondestructive examination of tubes, and neutralizing or removing sludge and other contaminants from the steam generators. In support of this effort, about 175 EPRI technical reports have been issued, together with several special guideline and technology transfer packages for utilities. These technical reports describe the causes of the corrosion and mechanical damage and evaluate corrective actions. Included are recommended methods on how the purity of the water can be improved and corrosion reduced. Specific levels of impurities are recommended. Several major types of remedial action are covered: prevention of cooling-water leaks in the condenser, prevention of air leaks, limitation of corrosion product buildup, removal of some impurities and neutralization of others.

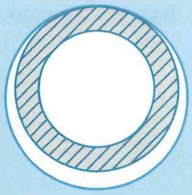
The SGOG Secondary Water Chemistry Guidelines (NP-2704-SR) have proved particularly useful. These guidelines tell utilities that the incidence of corrosion can be reduced by improving the purity of bulk secondary water in a steam generator.

To improve nondestructive examination of tubes, the use of multifrequency eddy current was encouraged by SGOG-I. These instruments have been used successfully in the field. Different kinds of tube damage and steam generator conditions can best be observed at different frequencies, and the new instruments can collect data on four or more frequency channels simultaneously. This allows assessment of tube integrity, sludge height, and the presence of denting during a single pass, which can substantially reduce inspection time and lower personnel radiation exposure.

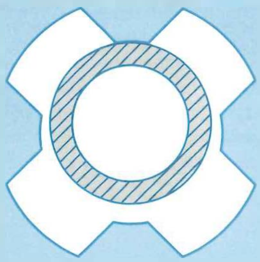
Sludge removal via blowdown (venting of accumulated material through a small port near the bottom of the steam generator) is not effective. Only about 10–25% of the sludge is removed by blowdown. For operating plants, therefore, emphasis is being placed on reducing the transport of corrosion products through the system and into the steam generator. This includes minimizing the introduction of oxygen into the plant, which causes the formation of corrosion products, and the use of condensate polishers, which can filter out much of the corrosion product materials. Condensate polishers are devices that can also remove ionic (dissolved) impurities from the water returning to the steam generator from the condenser.

By applying the recommendations and guidelines that emerged from SGOG-I research, utilities have been able to reduce forced outages at PWR power plants and increase the expected lifetime of the steam generators. In particular, tubes plugged and removed from ser-

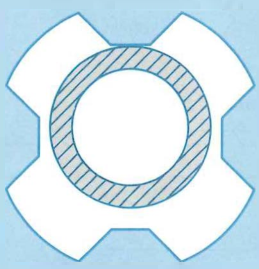
Drilled



Broached with concave lands



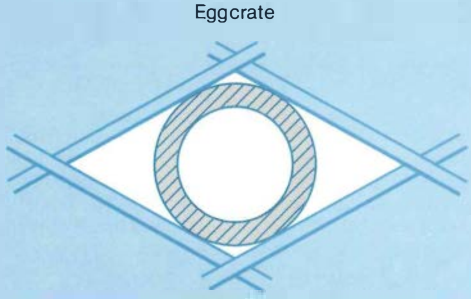
Broached with flat lands



Supports for steam generator tubes are a focus of crevice corrosion, which literally squeezes (dents) the tubes until they may crack. Circular drilled holes are the most susceptible because the very narrow gaps around the tubes are a perfect site for impurities to concentrate. The evolution of broached holes with three or four projecting lands has helped; while still affording support, these reduce the amount of contact between tube and plate.

The shape of the land surface has also evolved, from concave to flat; like the eggcrate assembly of narrow metal plates, the flat lands make only line contact with the tubes.

Eggcrate



vice because of denting have declined sharply. In 1977 more than 90% of tube plugging was caused by denting; in 1981 less than 10%. "SGOG-I research led to a better understanding of many of the most-severe steam generator problems," comments Green, "and it also produced improved technology in a number of areas that can be incorporated into future steam generator designs."

The challenge remaining

As the older problems, such as denting, have been controlled, others that were slower to develop have become more evident. Two of the most important of these are intergranular corrosion and stress corrosion cracking in the alloy 600 tubes themselves. In intergranular corrosion, the boundaries between the tiny grains of metal near the outer surface of a tube are slowly attacked by a process still not fully understood. This type of corrosion has been found so far in at least 22 plants. Recirculating steam generators have been particularly affected, with intergranular corrosion taking place in tubes on the hot leg (reactor water inlet) side of the tubesheet. It is thought that crevices in this very hot region still hold caustic materials left over from the early days of phosphate water treatment and that these impurities may be primarily responsible for the intergranular corrosion in some units.

Stress corrosion cracking is a related phenomenon that occurs when a surface exposed to a corrosive environment is also subjected to tensile (pulling apart) stress. Again, the process is not fully understood, but cracking can begin on either the inside or the outside of a tube, depending on conditions. Cracks that originate on the outer surface (exposed to secondary water) have occurred near the bottom tubesheet of recirculating steam generators and near the upper tubesheet of once-through steam generators. Both of these areas have concentrations of impurities, as well as stresses caused by internal pressure within the tube, high operating temperatures, and stresses remaining after the tubes have been manufactured (residual stresses). Cracks that originate on the inside of a tube generally occur near the U-bend in recirculating steam generators or in other mechanically deformed areas, such as inside the tubesheet. Some of these cracks have apparently resulted from inadequate annealing of the tubes when they were manufactured; others appear related to the additional stress on the tubes caused by denting. The cracks that have occurred inside the tubesheets are believed to be caused by the high stresses produced when the tubes were attached (expanded into) the tubesheet.

Pitting, a peculiar problem that is less widespread, has occurred in the sludge

CONTROL OPTIONS

1 Retube condenser.

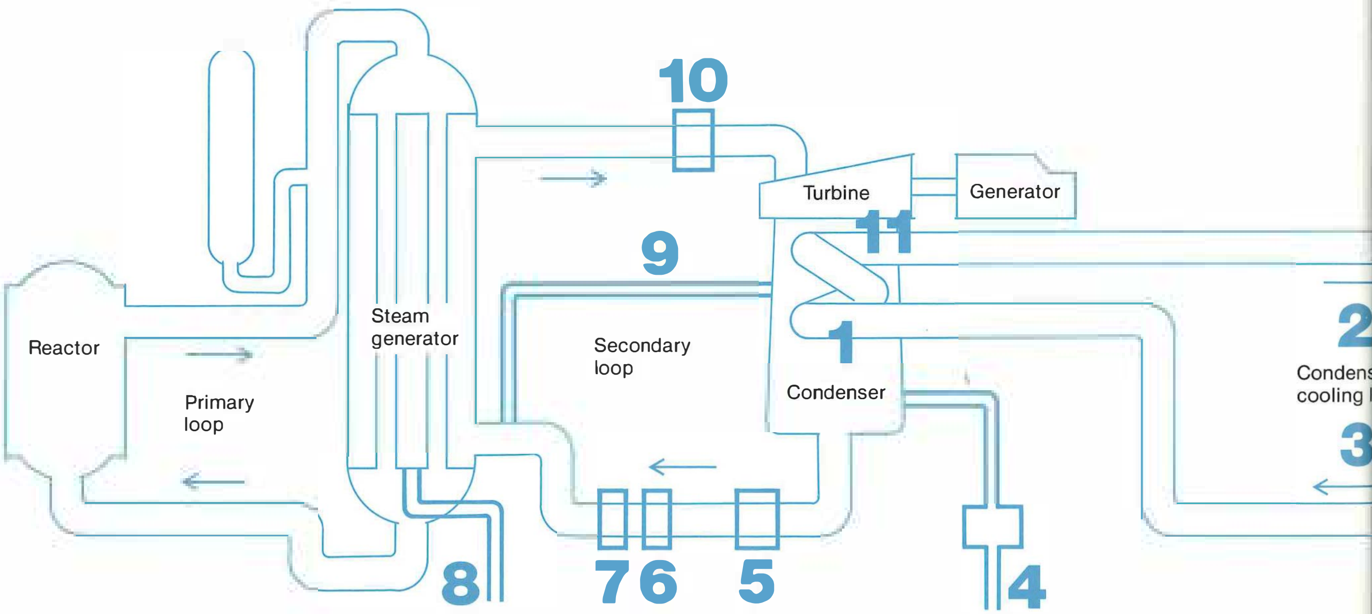
2 Conduct maintenance program to minimize inleakage of air and cooling water.

3 Install improved instrumentation for water purity and oxygen monitoring.

4 Improve operation of makeup water system (demineralization and deoxygenation).

5 Install full-flow condensate polisher.

6 Add deaerating feedwater heater.



7 Retube feed-water heaters with ferrous alloys.

8 Install blow-down processing system.

9 Add feedwater bypass return to condenser for startup cleanup.

10 Retube moisture separator–reheater with ferrous alloys.

11 Upgrade turbine generator expansion joint.

region of a few recirculating steam generators at seawater or brackish water sites and involves the dissolution of base metal from a very small area of tube surface.

A recent mechanical problem that has emerged is one of wear, or fretting. Antivibration bars (AVBs) are installed at the U-bends of the tubes to stiffen and brace them. Wear has been observed in steam generator tubes in the AVB region of about 10–15 units after about 5–8 years of operation. It is believed that the steam-water flow in this area causes vibration that leads to wear after extended periods of operation.

SGOG-II research

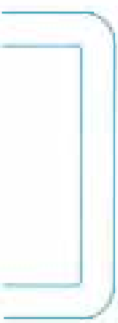
These problems and others that were identified after the SGOG-I research program was defined are now being addressed by SGOG-II. Top priorities of the new program include investigation of intergranular corrosion and stress corrosion cracking, determination of the causes of the cracks that originate inside tubes and the pitting that occurs on some tube exteriors, development and qualification of improved nondestructive examination techniques, further evaluation of chemical cleaning processes, further study of tube fretting, and development of ways to minimize the effects of sludge and improve tube support materials.

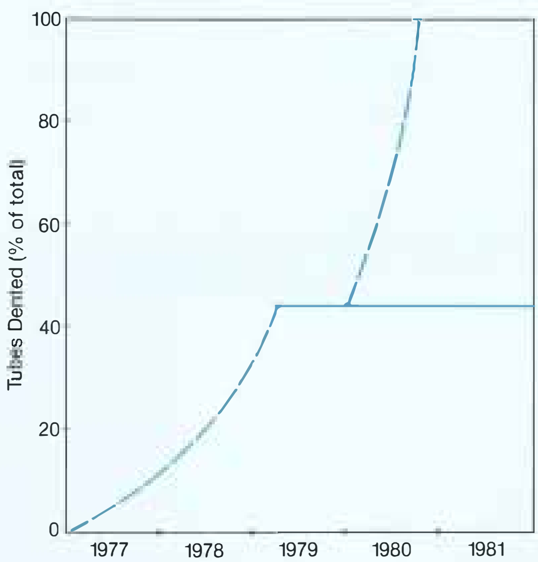
Some progress has already been made. Guidelines for steam generator inspection have been issued. Intergranular corrosion has been duplicated in the laboratory and evaluation of possible remedies is under way. Laboratory tests to duplicate pitting have been achieved, and plant conditions to be avoided have been identified. Improved methods of sludge removal are being evaluated. New data on the effects of tube support vibration have been gathered by model testing. And the evaluation of plant experience following application of SGOG-I water chemistry guidelines is under way.

"Everyone, utilities and vendors alike, can only benefit from overall improvements in steam generator technology," Green concludes. "Formation of SGOG I and II allowed the necessary research to proceed in an efficient, cooperative manner. These owner groups have also provided a unique opportunity for individual utilities to share vital information. There will be no quick solution to problems as complex as these, but a united effort is the best way to face them." ■

This article was written by John Douglas, science writer. Technical background information was provided by Stanley J. Green, Steam Generator Project Office.

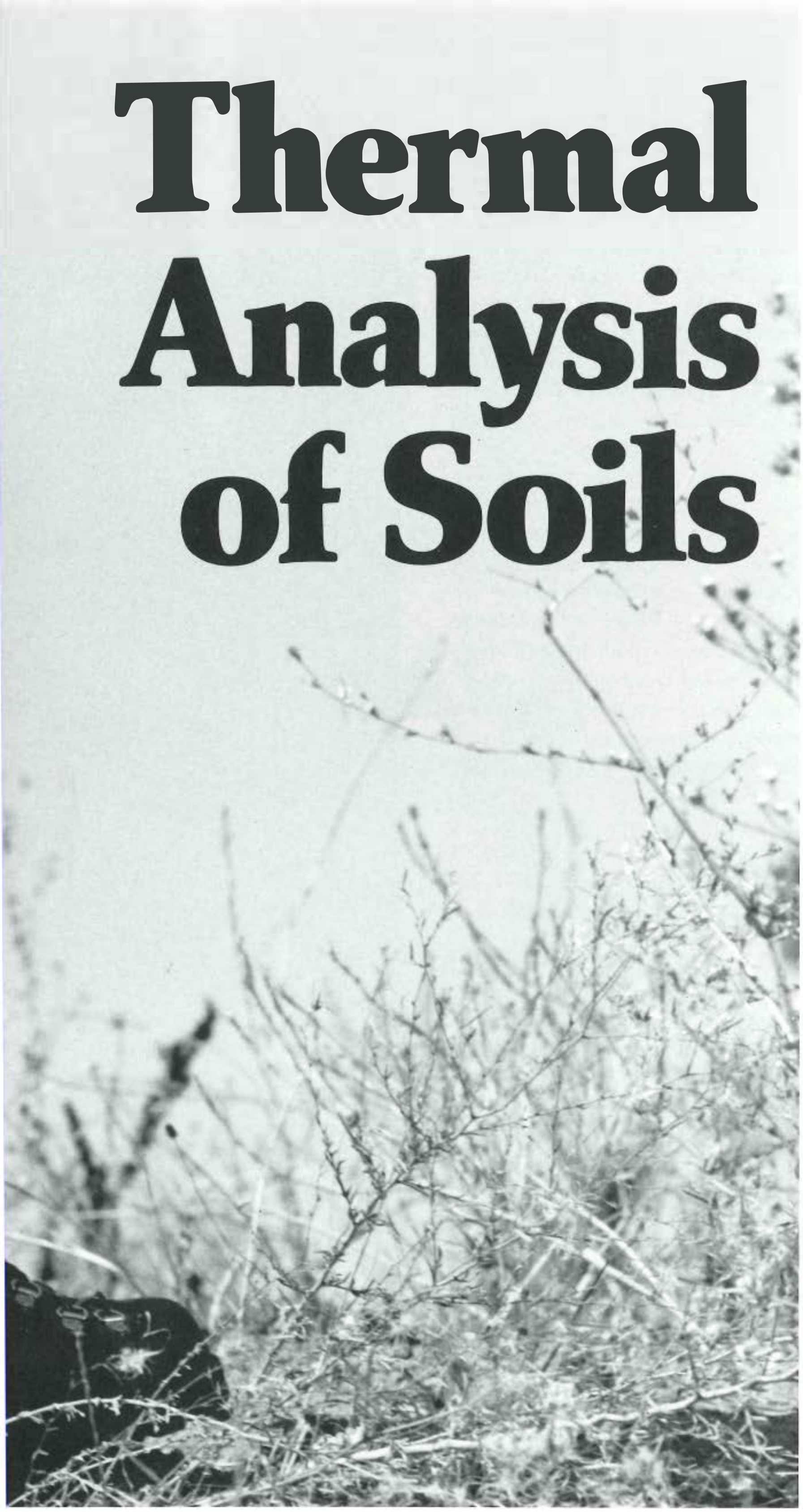
Opportunities for controlling steam generator corrosion and consequent mechanical damage involve equipment modifications and improved procedures in the secondary loop and especially in the condenser cooling loop, where vacuum conditions lead to the inleakage of impurities. Top-priority remedies are likely to be condenser retubing, a maintenance program to minimize subsequent inleakage there, and feedwater heater retubing with ferrous alloys.





Corrosion-caused denting of PWR steam generator tubes can be arrested by improved control of water chemistry in the secondary loop. When Unit 1 of Public Service Electric & Gas Co.'s Salem plant was shut down for refueling and modifications in 1979, more than 40% of its steam generator tube intersections were found to be dented. New measures in water chemistry halted further corrosion, which would probably have attacked the entire steam generator in less than one more year of operation.

Thermal Analysis of Soils



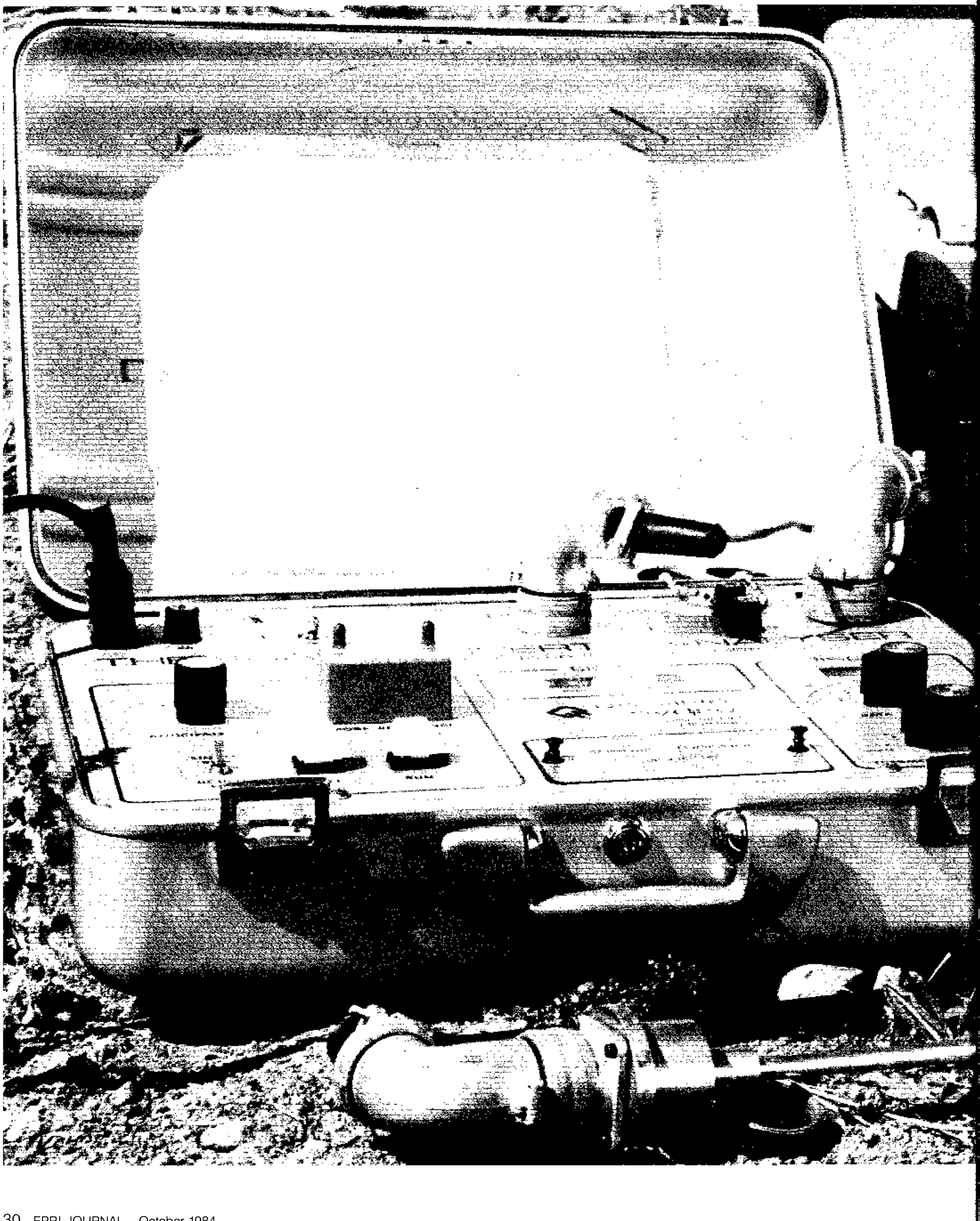
A portable instrument affords on-site analysis of soil thermal properties in 10–20 minutes, allowing utilities to rate underground cables quickly and confidently for the most-efficient load-carrying capacity.

How well a piece of equipment will perform in service is often a function of the environment in which it must operate. In the case of buried transmission and distribution cables, the secret to optimal performance lies largely in the ground—specifically, in the soil's ability to transfer heat away from the circuit. Unfortunately, understanding the thermal characteristics of cable backfill is often time-consuming and expensive, involving soil excavation and laboratory tests. In addition, thermal factors can be complicated by the effects of weather, seasonal load variations, and biologic burdens on soil moisture, such as trees or shrubs.

In view of these difficulties, utilities will sometimes simply assign conservative limits for the cables and accept the resultant losses in efficiency. To help utilities avoid such overconservative operating limits on their underground cables, EPRI and Ontario Hydro have developed the portable soil thermal property analyzer (TPA), which provides the three most important measurements of soil thermal properties, either on site or in the laboratory.

Key properties

The TPA determines the thermal resistivity, the thermal stability, and the thermal diffusivity. Of these three, thermal resistivity affects the thermal design of the cable most directly; the thermal resistance of the backfill or native soil determines the temperature rise in the cable itself, and the current running through the cable (cable ampacity) is limited by



the cable's operating temperature.

The heat flow through the soil surrounding the cable occurs primarily through the solid-liquid matrix of the particles and moisture in the soil. This means that thermal resistivity is not only a matter of soil density, but also largely a function of moisture content. At high moisture levels, liquid fills the gaps between soil particles and provides a continuous medium, an efficient thermal conductor to bleed away heat from the cable. When moisture content is reduced, the bridging between particles diminishes and thermal resistivity increases dramatically. The point at which the thermal resistivity suddenly increases at a runaway rate (the so-called critical moisture content) varies according to the packing efficiency (particle size distribution) of the soil. A soil with good distribution of particle sizes maintains fairly constant thermal resistivity down to moisture contents as low as ~2%.

The thermal stability of a soil, another key factor, is a function of the soil's ability to sustain an essentially constant level of resistivity above the critical moisture content. One mechanism that affects this stability is the tendency of water to vaporize near a heat source, such as a cable, and condense in cooler regions in the soil, away from the cable; liquid is returned to the area around the cable by another natural mechanism, capillary action. These two movements of moisture in the soil tend to maintain the distribution of moisture at a constant level. In good thermal soil—thermally stable soil—the thermal resistivity is essentially independent of moisture content above some critical level. In poor thermal soil, on the other hand, thermal resistivity changes substantially with soil moisture content, even above the critical moisture content.

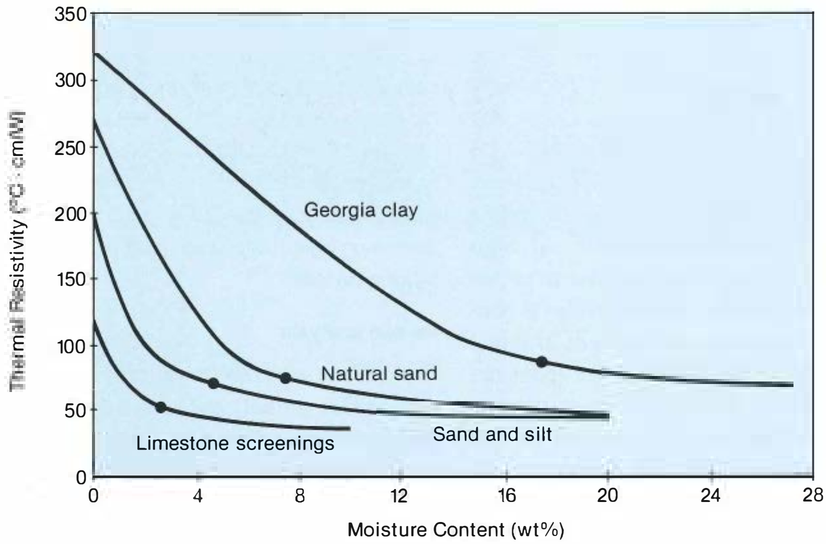
The third important property, thermal diffusivity, measures the ability of a material to absorb and conduct heat over a short period, typically several hours. This is an important measurement for predicting cable performance under transient and cyclic loading, when the load carried by the cable varies. The thermal diffusivity of the soil determines the maximum load capacity in the cycle. Although thermal diffusivity can be inferred from the heat capacity and thermal resistivity, the TPA can take the necessary readings and perform calculations on site.

On-site analysis

The TPA is a microcomputer-controlled system that gathers data via 6-ft (1.8-m) needle probes inserted into the soil. The processor acquires the readings from the probes, determines accuracy, and then displays thermal resistivity, thermal diffusivity, and change in thermal resistivity with heat flux, yielding the critical moisture level for soil stability. The processor's data base contains fundamental parametric values for soil types that have already been fully characterized; thus, the data from the particular soil being measured can be compared with the known data to ascertain soil type. In addition, the TPA suppresses erroneous data, eliminating much of the human error caused by poor probe insertion or contact resistance. With the advanced model, the TPA-5000, running calculations are displayed on a cathode-ray tube, and time and temperature data are printed out; all time, temperature, and current data are stored on tape cassette.

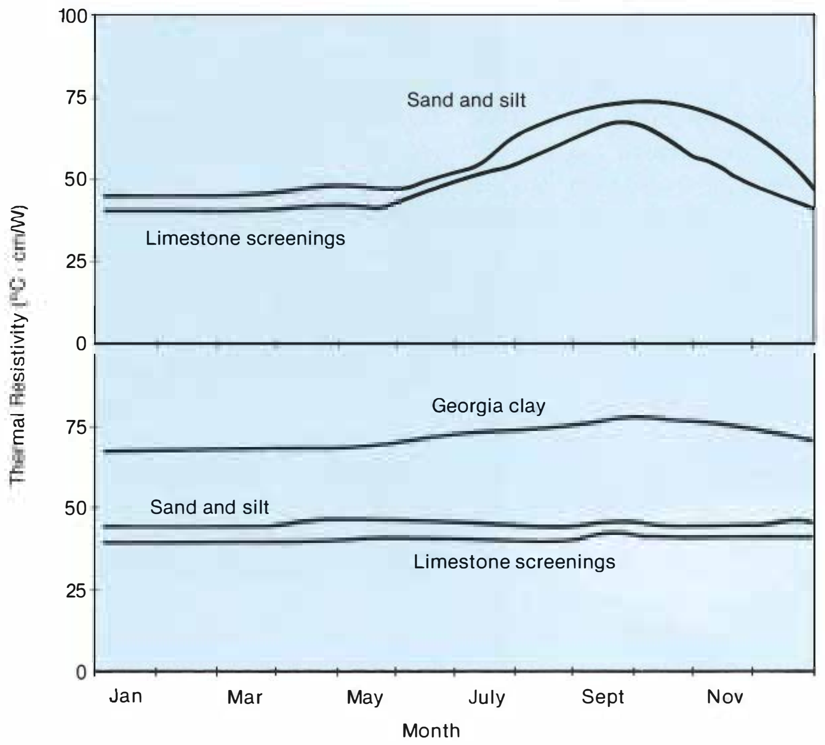
In addition to its development work on the TPA, Ontario Hydro compiled a computer program based on National Weather Service tapes. With this statistical weather analysis program (SWAP), seasonal variations in soil moisture can be calculated, and from those, load cycling and peak load-handling capabilities can be predicted.

Three prototypes for what is now known as the TPA-1000 were contracted for by EPRI and tested by several utilities throughout the country, each using the analyzers for a minimum of six months. San Diego Gas & Electric Co. used the TPA in conjunction with more traditional



Thermal resistivity varies with a soil's moisture content, which is, in turn, largely a matter of the packing efficiency of the soil. Limestone screenings, which typically have an excellent variation of particle sizes, display a low, fairly constant thermal resistivity down to 2% moisture content. The thermal resistivity for Georgia clay, which consists of very small, tightly packed particles, is normally higher and increases significantly when the soil dries out to below 18% moisture. The dot on each curve indicates the soil's critical moisture content.

Climatic conditions can have a strong effect on a soil's thermal resistivity. Average measured values for limestone screenings and sand and silt are comparable for the beginning of the year in Berkeley, California (top), and at an experimental site in Georgia (bottom). However, Berkeley normally has an extended period without rain in the summer, during which the soil dries out and resistivity increases. As expected, the thermal resistivity of Georgia clay is influenced more by summer heat than is the resistivity of other backfill materials at the Georgia site.



measurements in a study of the city's distribution system, performed by the University of California at San Diego. Potomac Electric Power Co. used the device to check measurements made much more laboriously in the 1950s and were pleased with the results. Arizona Public Service Co. tested the prototype in both laboratory and field tests; as a result, it adjusted the ratings of existing underground cables and designs for further installations. This company's evaluation of the TPA included successful comparisons with the conventional Shannon and Wells procedure for determining thermal resistivity.

Today, the thermal property analyzer is commercially available in two models: the standard TPA-1000 and the more expensive TPA-5000, which includes additional operational options and features. Both devices are manufactured by Geotherm, Inc., of Canada and distributed in the United States by Underground Systems, Inc. Also available is a thermal resistivity analyzer, which measures only resistance. In ongoing development work, contractors are modifying hardware and software to provide readings on just when a soil will reach a critical moisture level. This project will conclude in November, after which testing on the modified software and hardware will begin.

As Project Manager Thomas Rodenbaugh points out, savings from the TPA are largely indirect. Although time and labor are saved in making the actual measurements, the real savings come from the fact that utilities are now able to design and rate existing and new underground cables in an economical and efficient way. By assigning realistic and detailed thermal resistivities to native and backfill soils, utilities can optimize the operation of installed and future underground transmission and distribution cable systems. ■

This article was written by Stephen Tracy, science writer. Technical background information was provided by Thomas Rodenbaugh, Electrical Systems Division.

Renewed Interest in District Heating and Cooling

A National Academy of Sciences symposium looks at international experience to assess the feasibility of district heating systems for U.S. cities.

District heating and cooling uses the centralized production of energy and the heat that results to provide space heat and hot water for homes and businesses—steam or hot water is actually pumped through pipes to individual buildings in the district. An American invention, the first district heating system, was built in Lockport, New York, in 1877, and beginning around the turn of the century, numerous district heating systems were constructed in American cities. Such systems are now uncommon in this country, with most of the U.S. space and water heat generated at the home or business site by electric or gas-fired heaters. But district heating is widely used in parts of Europe, particularly in Scandinavia, and interest is growing in reviving the concept for significant application in the United States.

The first district heating systems were combined electric and steam operations, where the waste heat produced from electricity generation was used for residential or industrial heating. This system worked fine when electric generating plants were sited in large urban areas because the steam or hot water had to be transported only a short distance and relatively little heat potential was lost. As electric generating plants came to be sited outside urban areas because of noise and pollution, large transportation heat losses made the system infeasible, and the original cogeneration facilities were separated into two individual systems.

In some older U.S. cities, special steam boilers have now been built for the sole purpose of providing steam heat for district heating. District heating also exists in the United States in many institutional settings, particularly on college campuses and military bases. In Washington, D.C., the Smithsonian Institution is still heated by district heat, as are 112 federal buildings, including the White House and the Department of State.

But there is not the same commitment to district heating in the United States as there is in Europe. European interest began after World War II, with the rising price of oil and the new concept of using hot water in the systems rather than steam, which allowed easier transport and higher heat efficiency. The U.S. systems, most of which were developed before 1945, are almost all still steam systems.

European governments also encouraged the use of district heating through planning grants, tax credits, and subsidies to encourage cities to use energy more efficiently. The fact that most European utilities are municipal systems made it easier for the governments to coordinate the development of these systems.

Whether the United States could draw on this European experience was the focus of an international symposium held June 4–6, 1984, at the National Academy of Sciences in Washington, D.C. The Symposium on District Heating and Cooling was sponsored by the National Research Council of the National Academy of Sciences, the Royal Swedish Academy of Engineering Sciences, the French Agency for Energy Management, the Danish Ministry of Energy, and the United States departments of Energy (DOE) and of Housing and Urban Development (HUD).

The purpose of the symposium was to assess the status of U.S. district heating and cooling systems as compared with systems in countries where general public use is relatively widespread. The consensus of the experts who attended seemed to be that district heating has the potential to play a more important role in meeting U.S. heating requirements, helping to decrease the nation's reliance on oil, lowering energy costs, increasing efficient energy use, and providing opportunities for cogenerated heat and electricity.


District heating system power plant in Washington, D.C.

The symposium was divided into seven sessions, covering such topics as the international status of district heating and cooling, barriers to development, cost comparisons, and future prospects. It opened with speakers who provided overviews of district heating and cooling development in Europe and in the United States.

Gunnar Engstrom, vice chairman of the Royal Swedish Academy of Engineering Sciences, discussed district heating's role in helping to avoid future energy crises. "We have learned one lesson," he said, "and that is not to put all our eggs in one basket." Engstrom explained that district heating achieved its first commercial breakthrough in Europe after World War II, when planners recognized its effectiveness in providing heat to central city areas. The most rapid development occurred in the Scandinavian countries, whose harsh climates created long heating seasons, and then in several Eastern European countries. In the Western European countries, the first oil crisis led to the establishment of district heating systems, which then spread quickly.

"District heating's role in Europe today," Engstrom explained, "is to provide an economic heat supply and to allow efficient energy use through cogeneration, centralized heat production, and the use of different fuels." In some European countries, the increased popularity of electric heat pumps has created more opportunities to capture the heat in sewage effluent, seawater, and groundwater as heat sources. "In Sweden, where electricity costs are relatively low, water-based heat pumps could supply as much as 25% of district heat in a few years," commented Engstrom.

HUD Secretary Samuel Pierce, Jr., the next speaker, explained that district heating was widely used in the nineteenth century in the Northeast and Midwest areas of the country. But such systems almost disappeared when gas, oil, and electricity became cheap commodities. Nevertheless, Pierce believes that district heating and cooling holds promise today in the nation's search for alternative energy sources and technologies.

"The potential it holds as a cost-effective energy technology has never been fully explored in America. Yet a growing appreciation of its benefits has begun to take root and spread here," he affirmed. "Meanwhile, Europe has been showing us the possibilities. We might well be in the early stages of a rebirth of district heating as an important energy option for many of our communities." Among the advantages he noted were increased investment in and revitalization of communities, particularly cities; positive environmental impact; and the potential for using waste heat from power plants.

Following Pierce's comments, Donna Fitzpatrick, principal deputy assistant secretary for Conservation and Renewable Energy at DOE, outlined the agency's support of district heating projects. In one set of projects, grid-connected integrated community energy systems are being developed to cogenerate heat and electricity, with excess electricity sold to the local power grid. In other projects, eight urban power plants have been retrofitted for district heating to replace oil and natural gas in local service areas. And in a third set of projects, evaluations of using water-based heat pumps to extract low-grade heat energy from resources in the natural environment are being conducted.

Fitzpatrick said, "These projects have shown that development of large citywide district heating systems is capital-intensive and therefore unlikely to succeed in today's energy and financial markets. Rather, smaller-scale systems that take advantage of the existing infrastructure and concentrations of large heating demands and that expand incrementally as demand grows are the most probable choice for construction." The greatest effect on immediate development, she believes, probably would be "research and development in lower-cost, low-temperature-resource systems and small-scale packaged heat source units that can be acceptably sited at large thermal demand centers."

Barriers to Development

Potential barriers to district heating and cooling were discussed in the symposium's second session. William Hanselman, president of Resources Development Associates, an engineering consulting firm, cited numerous barriers, including high capital costs, long construction lead times, high interest rates, regulatory uncertainties, uncertainties over future fuel prices, and investors' limited knowledge of district heating. In addition to these conventional problems, he also noted a number of other barriers that he believes prevent large-scale market penetration. He noted what he called a basic contradiction in trying to create an infrastructure in the United States through private companies that are not attuned to such long-term investments. Hanselman also believes district heating proponents cannot look to investor-owned utilities to participate in its development. "As the investor-owned utilities in the United States go through their own struggle to figure out what they're going to be doing in the year 1995, it's a bit uncertain in my mind whether we can expect them to put a lot of emphasis on district heating in the next 15 years."

Another barrier is the burden of having to absorb inordinate amounts of front-end predevelopment cost in order to do a project. Finally, he sees a typically American need for immediate gratification, which is inconsistent with the required long-term infrastructure development. Hanselman does, however, see some progress, saying, "On a project-by-project basis, the United States is becoming quite successful in overcoming these hurdles to specific projects."

Two speakers from abroad discussed some of the factors that have contributed to the success of district heating in their countries. Lars Netzler, president of Vasteras Heat and Power Co. of Sweden, commented that his country faced many of the same barriers when systems were started years ago. He offered two keys for good results: gaining and keeping a good reputation with customers and maintaining close contact with local organizations. Jean-Michel Couderc, director for Geothermal Energy at the French Agency for Energy Management, discussed the role the French government had played in encouraging district heating systems to use geothermal energy.

HUD's view of district heating was also expressed by Stuart Sloame, the agency's deputy assistant secretary for Community Planning and Development, who said, "We look on district heating and cooling as an economic development tool for our cities, especially older ones, to retain their economic viability and to be competitive." He noted that although government resources are not plentiful, private enterprise has shown that it can operate successfully if there is potential for profit. The challenge is "to reduce the barriers to the private sector involvement—the institutional barriers and the financial barriers, namely the interest cost rate." Sloame also pointed out district heating's potential for helping cities solve their refuse disposal problem by recouping the cost of refuse burning through sales of the heat generated in the process.

John Millhone, director of DOE's Office of Building Energy Research and Development, noted two very influential uncertainties in the future of district heating and cooling—future government policies and energy prices. "We are not apt to see any new large centralized systems being built or even started in the United States in the immediate future as long as these uncertainties exist," he predicted. The solution is to find opportunities to construct financially feasible stand-alone systems that later could be connected to larger centralized systems.

The symposium's third session, focusing on the international status of district heating and cooling, included remarks by representatives of countries where district heating meets a significant portion of energy needs—Denmark, Finland, the Netherlands, Sweden, and West Germany. Eric Willis, director of Energy Research Development and Technology for the International Energy Agency, pointed out that development of many systems was prompted by government support and leadership, particularly at the local level. "Now," he commented, "district heating competes on the open market with other heating options." In Scandinavia, service is provided by municipal utilities, and there has been no competition from natural gas; comparing this situation with conditions in the United States, Willis noted, "At a time when the United States is busy sacrificing the world's finest telephone system on the altar of multiple choice in a free market, one begins to appreciate the difficulties in reversing that trend."

Most other European governments generally favor district heating, according to Willis, and offer some financial assistance to develop systems, but the main impetus for development is found on the local level. "District heating remains essentially a community endeavor," he explained, "based on a marriage between inspired and dynamic leadership on the one hand and a willing society of consumers on the other."

Competitive Costs

Making district heating and cooling systems financially competitive is crucial to their success, and the symposium's fourth session focused on costs. Speakers pointed out that costs vary, depending on such factors as fuel costs, system design, and financial conditions. Ishai Oliker, manager of Renewable Energy Technologies at Burns and Roe, Inc., said that many utilities serving downtown areas in the United States are burning oil and gas in aging steam-heating systems. As a result, they find it impossible to make a profit or compete for customers. However, by using hot water systems that cogenerate heat and power and use refuse or coal for fuel, Oliker said, "we can improve the economics substantially."

Oliker cited several projects in this country where costs have been influenced by such factors. For example, a small municipal utility in Willmar, Minnesota, was able to compete effectively with natural gas and oil supplies by burning coal in a cogeneration system that uses hot water. Thus, the utility, which sold heat in 1983 for $7.30 per million Btu, was able to make a profit.

Michael Karnitz, project manager at Oak Ridge National Laboratory, also pointed out the cost advantages of hot water systems. Karnitz said that although several hundred hot water systems are operating in Europe, they are only now beginning to appear in the cities of the United States. Four new hot water systems—in Trenton, New Jersey; Willmar, Minnesota; St. Paul, Minnesota; and Piqua, Ohio—demonstrate that the hot water system technology is cost-effective, according to Karnitz. Among the technology's advantages he cited were faster construction rates, higher energy efficiencies, and lower construction costs.

Fred Strnisa, project manager at the New York State Energy Research and Development Authority, provided an overview of prospective district heating and cooling costs in New York, a state that has initiated a series of projects to stimulate district heating. In calculating costs, Strnisa noted the advantages of a district heating system that uses coal or municipal solid waste for fuel. He also pointed out the financial advantage of using or selling to a utility electricity that is cogenerated and of retrofitting an existing power plant for use as a thermal source. Among the projects under way is an analysis of a proposed system for Jamestown, New York, that would use an existing coal-fired power plant retrofitted to cogenerate electricity as well as hot water for the system. The 13.5-MW system, which would require an investment of about $3 million, plus $1 million to convert customer systems, would provide heat at competitive prices, according to Strnisa.

Another system under consideration for agency study would be located in Dunkirk, New York, with a coal-fired power plant owned by Niagara Mohawk Power Corp. as the proposed thermal source. The warm condenser cooling water from the plant would serve as a heat source for heat pumps. During the summer, lake water would be used to provide cooling water for air conditioning.

Government's Role

Community planning in district heating development was the focus of session five, which included a speech by Mayor George Latimer of St. Paul, Minnesota, a city that soon will complete a hot water district heating system for its downtown area.

Latimer told the audience that establishing district heating systems requires public sector commitment on the local level. "You're talking about a major overhaul of the way we heat our cities," Latimer said, "and I don't think it's going to be done by the free market. The market cannot take care of the heavy front-end investment." As Latimer explained, St. Paul's system, which cost $45.8 million itself, plus about $22 million to convert various buildings to be served by it, was financed with federal, state, and local funds.

Latimer also called for a national energy policy recognizing that "the economic development future of our population centers, the security of our country, and the well-being and peace of the world are related to how we treat and share the precious, dwindling fossil fuel resource." And, he added, "If that's true, a major commitment on the public financing side is important in order to get out ahead of the crisis period."

St. Paul's system is expected to have about 80 customers by the end of 1984. The city hopes eventually to have a citywide district heating system and to cogenerate heat and electricity.

Also speaking on national policy was Representative Richard Ottinger of New York, chairman of the House Energy and Commerce Committee's Subcommittee on Energy Conservation and Power, who said, "I think the time has come to bring

Latimer Ottinger Carlson

the use of our pioneering efforts back home again." Ottinger noted that district heating development and combined heat and power generation in European countries are the result of national decisions. He suggested that much can be done in addition to the assistance provided by HUD and DOE to encourage district heating in the United States.

"There appears to be enormous potential for electric power plants to capture the waste heat they generate," Ottinger commented, and he suggested as one option that Congress require state regulatory commissions to develop programs for capturing and using this heat. "If there is a bottom line, it is that the United States can no longer afford to ignore the opportunities to utilize domestic resources that can be used cleanly and economically by district heating and cooling systems. The United States has to put to work the thermal energy now wasted in electric generation and other industrial processes."

District Heating and Electric Utilities

The utility interaction with district heating development was the focus of the symposium's sixth session. Carl Avers, president of the Youngstown Thermal Corp., explained that electric utilities initially became involved in district heating to attract additional electricity customers. Avers remarked that in this country, from an institutional standpoint, district steam systems were born of compromise and negotiation rather than a genuine interest in being in that business. Then electric utilities began siting large power plants away from urban areas, and in the mid 1960s, most electric utilities decided to drop their district heating systems. "Because utilities have become so large and are confronted with such big issues as completing nuclear plants, siting coal-fired plants, and dealing with having excess reserves, they're faced with a lot of financial, environmental, and technical problems; they really don't want to handle the same types of problems with a small enterprise—district heating," commented Avers. Avers expressed his view that electric utilities should not be involved in the district heating business. "Steam systems have to be operated by a company that's exclusively interested in the steam business and its development for its own benefit and that of the steam customers."

Avers cited several district heating systems that have been taken over from electric utilities by other concerns. These included the Youngstown, Ohio, system acquired from Ohio Edison Co.; a system in Baltimore, Maryland, acquired from Baltimore Gas and Electric Co. (BG&E); and a system in St. Louis acquired from Union Electric Co. Avers believes district heating has a promising future. "We will see district heating and cooling become more popular in our country because it is truly the most economic way of cooling and heating building complexes that are close to each other."

Other session speakers included Michael Gagliardo of the Northeast Maryland Waste Disposal Authority, who provided the symposium audience with a summary of the agency's development of a 2250-t/d waste-to-energy system, now under construction, and its dealings with a local utility. The facility is designed to provide a solution to the problem posed by lack of adequate waste disposal capacity in the Baltimore area.

Gagliardo explained that the authority originally hoped to sell thermal energy produced by the plant to BG&E, which owned and operated a steam district heating system serving 600 customers in the downtown area. However, because BG&E was interested in concentrating on the gas and electric portion of its operation, the authority had to plan a facility that would derive its revenue from electricity sales.

The authority found that the revenue it could derive from electricity sales to

BG&E was relatively low because the utility, which generates most of its electricity from coal and nuclear power plants, has kept its costs down. Although Gagliardo said the agency expects to sell BG&E electricity cogenerated by the plant, it hopes to develop other thermal markets that offer more attractive prices. Gagliardo noted that two events occurred recently to set the stage for the development of those markets—BG&E's sale of its district heating system and the completion of a HUD-sponsored district heating and cooling assessment.

The symposium's final session was devoted to summations and additional comments from speakers and members of the audience. Summarizing the session covering the international status of district heating and cooling, Lee Schipper of Lawrence Berkeley Laboratory said the audience heard all the countries report that although the technologies and economics must be right, there is an overriding societal element. "Maybe our goal is to make recommendations on how to match the various technology options with the various social parameters of a community," he commented. "A lot of the weighing of costs and benefits is, for better or worse, going to be done in a social and political framework, not simply as a result of an engineering calculation."

James Reilly of Consolidated Edison Co. of New York, Inc., summarized the speeches presented in the session on comparing costs and added, "When we look at the barriers to district heating, they're all interwoven; the political climate, the social and economic climate, the local restrictions—we can trace almost all these back to the bottom line, and that is, can a district heating project make a go of it strictly on economics?"

Commenting on the last two sessions, engineering consultant Clinton Phillips said one message he received was that district heating and cooling systems are viable. However, because the country does not have a national policy supporting them, "we must do those things that bring a positive image to offset the almost tragic impression that district heating is a failure in this country."

Phillips said the sessions also pointed out the value of district heating in using heat sources previously considered as waste—recovering energy from municipal waste, cogeneration, industrial processes, water systems, and other sources. "Let's look at the value of energy conversion in terms of protection of our finite resources. That's why district heating and cooling is a national ethic that we should pursue."

Thus, district heating and cooling may increase its share of the energy market in the years ahead. Although the introduction of large, new, centralized systems seems unlikely in the near future, more, smaller systems may prove feasible, opening up new opportunities for cogeneration and providing Americans with a seemingly new source of heat that has actually been around for a century.

A copy of the final report of the Symposium on District Heating and Cooling is available from the National Academy of Sciences, 2101 Constitution Avenue NW, Washington, D.C. 20418. ■

This article was written by Doris Newcomb, a freelance writer who specializes in energy issues.

Board OKs $8.8 Million National Forest Study

Research at nine sites will attempt to quantify the link between acid deposition and changes in forest nutrient systems.

At its August meeting in New Orleans, the EPRI Board of Directors approved an $8.8 million research project to assess the effects of acid deposition on forest systems. The project, the biggest yet undertaken by the Ecological Studies Program, will begin in early 1985. Work will focus on soil processes, canopy interaction, and elemental accumulation and losses.

"Better scientific information on the effects of atmospheric deposition, including acid rain, may give decision makers a better basis for making regulatory and legislative judgments," explains Vice President René Malès.

The project will focus on answers to four specific questions: how acid deposition is modified by canopy processes; how soil nutrients are affected by canopy throughfall; what the relationship is between atmospheric and canopy concentrations of dry deposition; and how these processes can be linked for predictive purposes by a mathematical model.

The project marks the first time researchers will quantify, or mathematically document, how atmospheric deposition and canopy and soil processes are linked to a forest's nutrient status. Previous EPRI projects on forest decline looked separately at how acid deposition affects tree canopy processes, soil processes, and nitrogen cycling. During this work, questions arose about the interrelationships between these processes within an ecosystem.

Oak Ridge National Laboratory will be the prime contractor for EPRI. Nine research sites that include both dying and healthy forests have been chosen for the project. The forests were selected to represent a range of conditions in climate, air quality, soil type, and vegetation; concentration of acids and acidifying compounds in the atmosphere; and concentration of sulfur, nitrogen, and hydrogen in the soil.

Two forests, one of Douglas fir and one of red elder, were chosen as sites in the Cascade Mountains of Washington State, as was a loblolly pine forest near Oak Ridge, Tennessee. Also selected as sites were two forests of spruce and hardwood in the Great Smoky Mountains National Park, a mixed hardwood-conifer forest at Coweeta, North Carolina, a Huntington Forest hardwood stand near Syracuse, New York, and two stands of spruce and fir on New York's White Face Mountain. Other forests in the United States and sites in Canada, Germany, and Norway may be added to the project if funding permits.

Malès notes that researchers will use data developed in recent EPRI and EPA studies, including EPRI's aluminum biogeo chemistry study (ALBIOS) and the integrated lake watershed acidification study (ILWAS). In fact, several forest sites in the new project were also used earlier in ILWAS and ALBIOS. ■

Board Vacancies Filled

In other action at the August meeting, EPRI's Board approved two interim appointments to fill vacancies created by the resignations of Charles J. Dougherty, chief executive officer of Union Electric Co., and William B. Reed, president of Southern Company Services, Inc. The newly appointed executives are John J. Hudiburg, president and chief executive officer of Florida Power & Light Co., and Sherwood H. Smith, Jr., chairman of the board, president, and chief operating officer of Carolina Power & Light Co.

Smith

Hudiburg

Also announced at the meeting was the appointment of six members to the Advisory Council. Composed of distinguished individuals from outside the utility industry, the council provides advice to the Board, officers, and staff on directions in which EPRI's research program should move to meet the broad needs of society.

The following new members will serve until June 30, 1988: Stephen Brobeck, executive director of the Consumer Federation of America; David Allan Bromley, professor of physics and director of the A. W. Wright Nuclear Structure Laboratory at Yale University; Robert Alan Charpie, president and director of the Cabot Corp. in Boston; Brian MacMahon, chairman of the epidemiology department at Harvard University School of Public Health; Laurence I. Moss, a consultant in energy and environmental design and policy analysis; and Herbert Horace Woodson, director of the Center for Energy Studies at the University of Texas. ■

Utility Coalition Sponsors University Monograph Series

In the course of its continuing effort to keep university instructors informed about R&D activities, EPRI has learned there is a shortage of adequate textbooks for students enrolled in senior and graduate power engineering courses. "One of the biggest difficulties is that publishers are not interested in printing much-needed notes because of the limited market for them," reports Howard Jurewitz, assistant to David Saxe, senior vice president of Finance and Administration. "What's been needed is a central clearinghouse to print and distribute material that is available in note form from professors."

As a first step toward remedying the situation, the Power Engineering Society's Power Engineering Education Committee (PEEC) created an ad hoc committee consisting of six power engineering professors and representatives from EPRI, the American Public Power Association, Edison Electric Institute, and the National Rural Electric Cooperative Association. The ad hoc committee proposed the formation of an editorial board to oversee the writing, publication, and distribution of educational monographs on power engineering, based on notes gathered from leading professors in the field. PEEC officially approved the monographs project at its meeting in Dallas this past February. Charles Gross of Auburn University, who was named chairman, worked at EPRI this summer to get the program off to a fast start.

The monographs are designed to be used as text material in advanced college-level course work and continuing education. Printing and distribution costs will be shared initially by the industry coalition, with EPRI serving as the key distributing member. Monographs will be available at cost to those involved with power engineering education. The goal is to make the project self-supporting.

Helping our universities to develop scientists and engineers in the field of electricity will benefit the entire electric utility industry, Jurewitz believes. "Our industry is having an increasingly difficult time recruiting engineering and scientific graduates, especially in the power options. Helping academia will not only benefit the university systems, but through continuing education we will be able to bring some of these monographs into our own training and development programs." ■

CALENDAR

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

OCTOBER

15
Seminar: Coal Transportation Costing
Kansas City, Missouri
Contact: Edward Altouney (415) 855-2626

15–18
Seminars: Fuel Supply
Kansas City, Missouri
Contact: Howard Mueller (415) 855-2745

16–18
Seminar: Buildings and Their Energy Systems—Technologies and Planning Strategies
St. Louis, Missouri
Contact: Orin Zimmerman (415) 855-2551

16–18
Hydro O&M Workshop and Seminar: Dam Safety
San Francisco, California
Contact: James Birk (415) 855-2562

23–24
Seminar: Estimating Retrofit FGD Costs
Denver, Colorado
Contact: Thomas Morasky (415) 855-2468

23–25
Workshop: Power Plant Performance Monitoring
Washington, D.C.
Contact: Frank Wong (415) 855-8969

31
Integrated Lake Watershed Acidification Study
Washington, D.C.
Contact: Robert Goldstein (415) 855-2593

NOVEMBER

5–7
Electric Field Effects Research
St. Louis, Missouri
Contact: Gorden Newell (415) 855-2573

8–9
15th Semiannual ARMP Users Group Meeting
Hartford, Connecticut
Contact: Walter Eich (415) 855-2090

12–15
Second International Conference on Electrostatic Precipitation
Kyoto, Japan
Contact: George Preston (415) 855-2461

13–14
Regional Conference: Compressed-Air Energy Storage
Washington, D.C.
Contact: Robert Schainker (415) 855-2549

13–15
Preventive Maintenance Model
Charlotte, North Carolina
Contact: Howard Parris (415) 855-2776

13–15
Seminar: Condenser Failures
Palo Alto, California
Contact: Barry Syrett (415) 855-2956
or Roland Coit (415) 855-2220

13–16
Symposium: Dry SO_2 and Simultaneous SO_2–NO_X Control Technologies
San Diego, California
Contact: Michael McElroy (415) 855-2471

14–16
Symposium: Market Research for Electric Utilities
Dallas, Texas
Contact: Joseph Wharton (415) 855-2924

28–29
6th Annual EPRI NDE Information Meeting
Palo Alto, California
Contact: Soung-Nan Liu (415) 855-2480

JANUARY

16–17
Regional Conference: Compressed-Air Energy Storage
New Orleans, Louisiana
Contact: Robert Schainker (415) 855-2549

MARCH

13–14
Regional Conference: Compressed-Air Energy Storage
San Francisco, California
Contact: Robert Schainker (415) 855-2549

APRIL

30–May 2
Hydro O&M Workshop and Seminar: Dam Safety
Boston, Massachusetts
Contact: James Birk (415) 855-2562

MAY

6–9
1985 Joint Symposium on Stationary Combustion NO_X Control
Boston: Massachusetts
Contact: Michael McElroy (415) 855-2471

14–15
Regional Conference: Compressed-Air Energy Storage
Chicago, Illinois
Contact: Robert Schainker (415) 855-2549

R&D Status Report
ADVANCED POWER SYSTEMS DIVISION

Dwain Spencer, Vice President

HIGH-RELIABILITY GAS TURBINE COMBUSTION

Modern combined-cycle plants have the best heat rates of any major generation equipment in their capacity range. Any improvement that can increase their reliability and availability would directly benefit the operating economics of utilities that use combined cycles to generate baseload power. The development of a high-reliability combustion system that reduces wear rate, allowing longer intervals between combustion inspection and parts replacement, is a significant step in this direction. This project successfully evaluated the performance and demonstrated the extended life of a high-reliability combustion system (RP1801-1).

According to utility operating and maintenance experience with large baseload combined-cycle units that use water injection for control of nitrogen oxide (NO_x) emissions, the wear rate of combustion hardware components necessitates inspections approximately every 3000 fired hours. Similar machines operating without water injection, however, can accumulate 8000 fired hours between combustion inspections. It was therefore suspected that flame-pulsation-driven pressure oscillations, amplified by water injection, are a strong contributing factor to combustion system wear.

Combustion system configurations

The test engine for the project was a combined-cycle unit (No. 33) at the T. H. Wharton plant of the Houston Lighting & Power Co. (HL&P). This unit is a General Electric Co. MS7001B gas turbine exhausting into a General Electric unfired heat recovery steam generator; it is a gas-fired unit with oil-firing capability.

In the standard configuration, each of the 10 combustion chambers, axially oriented on the engine's circumference, contains one dual-fuel nozzle. Water for NO_x suppression is injected by spray heads mounted on the fuel nozzle body.

The combustion chamber liner is a thin-gage alloy steel shell with air holes and slots to provide combustion air, flame-dilution air, and film-cooling air. The hot combustion products discharge from the combustion chamber into a transition piece, a curved duct with a heavier wall and a warped surface. This duct changes the flow crosssection of the hot gas from circular at the combustion chamber outlet to 36° of angle annular at the turbine stator vane inlet. Figure 1 shows the physical arrangement of these parts.

Thermal expansion requirements dictate that the combustor liner and transition piece must be assembled with a sliding fit relative to each other and with a sliding fit gas seal between the transition piece outlet and the turbine inlet vanes. These sliding fit interfaces are subject to wear if excessive relative motion occurs between adjoining components. Acoustic frequency relative motion, caused by dynamic pressure phenomena induced by flame pulsations, is a major cause of the wear between these parts.

In developing a dry low-NO_x turbine combustor (i.e., a combustor arranged for staged combustion that would not require water injection for NO_x suppression), General Electric noticed that using six fuel nozzles arranged at the vertexes of a hexagon in each combustion chamber (instead of one fuel nozzle at its center) caused flame-pulsation-induced dynamic pressure fluctuations in the combustor to decline in amplitude. This showed potential as a means of reducing the wear rate of the transition piece, combustor liner, and gas seals in water-injected machines.

To demonstrate to the industry the effectiveness of the low-noise technology in reducing wear, EPRI and HL&P funded a project under a cost-sharing arrangement with General Electric. The objectives of this effort were to (1) evaluate the performance of the multinozzle, high-reliability combustion system, comparing it with the baseline system, and (2) carry out an endurance test to establish that longer combustion inspection intervals could be achieved.

Performance evaluation

The initial phase of the project took place at General Electric's combustion laboratory in

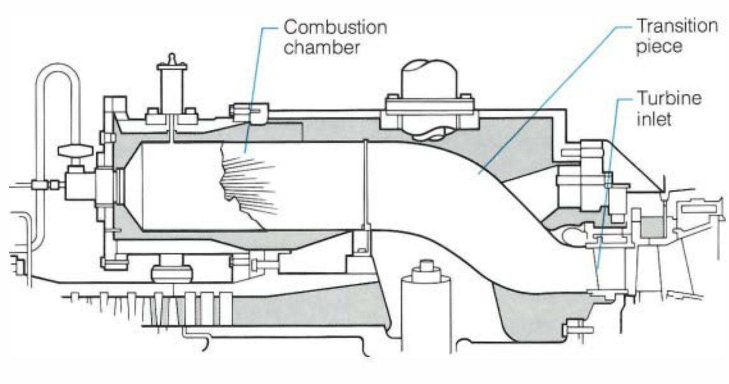


Figure 1 Combustion chamber and transition piece assembly, showing its relative position to the turbine inlet.

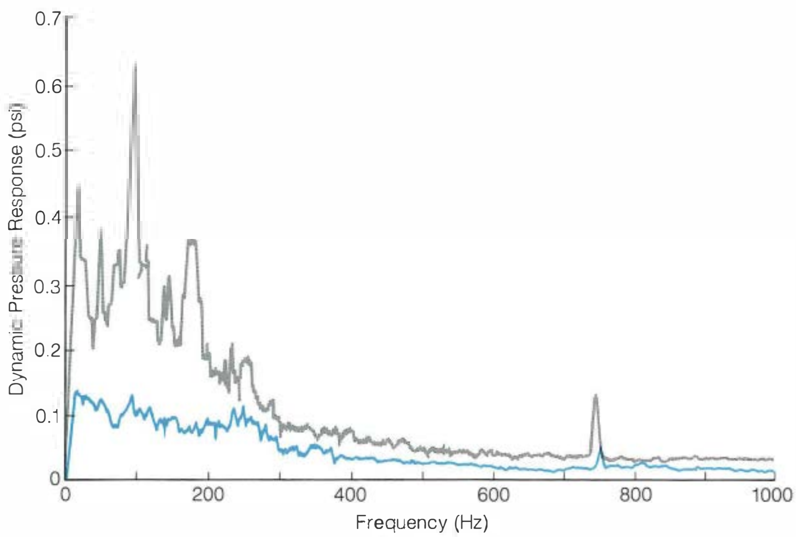
Schenectady, New York. A single full-size combustion chamber with the multinozzle configuration and pressure was placed on a test stand at full flow to establish the correct combustion mixing–air hole pattern, the combustor liner and center core-cooling configuration, and the effective area of the fuel nozzle gas tip. When all design parameters had been determined, a multinozzle combustor, configured for the engine endurance appraisal, was tested on the same test stand. The combustor was instrumented for metal temperature, dynamic pressure, and gaseous emissions. It was then tested with methane and No. 2 petroleum distillate fuel over a test matrix simulating various engine conditions with and without water injection.

The results of these full-scale single-combustor tests demonstrated the adequacy of the design.

- Metal temperatures ranged 700–1000°F (371–538°C) for petroleum distillate fuel and 600–900°F (316–482°C) for methane, well below the limits for the Hastelloy-X material of the combustor.
- Water injection rates to achieve the required NO_x reduction were at acceptable levels.
- The dynamic pressure spectra for the multinozzle system without water injection were virtually identical for both oil and methane fuels.

Dynamic pressures for each fuel with water injection were dramatically less than those of a standard single-nozzle MS7001 combustor—pressures were less than 0.1 psi (690 Pa) peak-to-peak, with no significant peaks. This is in contrast to a sharp peak of approximately 0.2–0.5 psi (1.4–3.4 MPa) found at 200 Hz for the single-nozzle production combustor. With these data to provide confidence in the system, General Electric prepared 10 multinozzle combustors with appropriate instrumentation for installation on Unit 33.

Figure 2 Comparison of the dynamic pressure response of the single-nozzle (gray) and the multinozzle (color) combustion chambers with compliance-level water injection.



Field testing

Prior to the start of field testing, personnel removed the existing standard combustion hardware from the unit and inspected it to provide baseline wear information. The transition pieces had run 3902 hours since the last weld repair and straightening (for creep); before that, the transition pieces had run 3083 hours, for a total of about 7000 fired hours. The combustor liners had run about 6000 fired hours. This hardware was replaced with new Block III transition pieces and single-nozzle combustor liners for baseline testing. Subsequent multinozzle engineering tests and the multinozzle endurance tests used these same transition pieces.

The field test on Unit 33 began in March 1981 with baseline testing of the standard single-nozzle combustion system—using both petroleum distillate and natural gas fuels, with and without water injection, over a matrix of load points. Two transition pieces were each equipped with four accelerometers and seven strain gages. Two combustor liners were each equipped with eight metal temperature thermocouples, and each combustion chamber (as well as the fuel and atomizing air manifold) was equipped with dynamic pressure instrumentation.

Emissions tests for O_2, CO, NO_x, and unburned hydrocarbons were performed by stack gas sampling. Firing temperature, air flow, fuel flow, water flow, load, and exhaust temperature were also recorded to permit performance comparisons between the baseline system and the multinozzle system.

On completion of the single-nozzle baseline tests in April 1981, the standard combustion hardware was removed for inspection and the multinozzle hardware was installed. This installation included the Block III transition pieces used in the single-nozzle baseline tests, which by this time had experienced 18 fired hours and seven starts.

The engineering test with the multinozzle hardware repeated the baseline test matrix run earlier with the standard combustion hardware. Then the compressor was washed, and the major portion of the test matrix was rerun. After this engineering test, the temperature and accelerometer instrumentation was removed from the combustors and transition pieces, and the endurance test began. Figure 2 compares the dynamic pressure response of the single-nozzle and multinozzle combustion systems.

Endurance testing

The objective of the endurance test was to demonstrate that the high-reliability combustor system can operate with combustion inspection intervals of 8000 fired hours instead of the current practice of 3000 hours when running with water injection. To accurately monitor wear rate, the first inspection after the start of endurance testing took place in late May 1981, after 520 fired hours. The remaining inspections in the project were scheduled at 2000, 5000, and 8000 total fired hours.

The nominal 8000-hour inspection actually occurred at 9100 hours in September 1982 because dispatch requirements prevented earlier shutdown of the unit. At that inspection, the accumulated wear of the combustion system parts (with the exception of three transition pieces that had to be replaced because of wear) was small enough to suggest that intervals of 13,000 hours were possible. The test was therefore extended to 13,000 hours.

After an additional 800 operating hours, the unit went into an extended forced outage in December 1982 for reasons unrelated to the test. The unit restarted in July 1983, but the test was terminated in November 1983 (after 12,200 total fired hours) when the unit was taken off the line—again for reasons unrelated to the test.

Project results

The multinozzle combustor configuration successfully reduced combustion component wear rate to a level that would allow inspection intervals to be extended to 8000–9000 hours. However, because of the wear noted on those three specific transition pieces, the interval could not be extended to 13,000 hours. The amplitude of the flame-driven dynamic pressure pulsation associated with multinozzle water-injected combustion was reduced by a factor of 5–10 relative to single-nozzle combustion. This suggests that dynamic pressure pulsation is a major contributor to combustor component wear. Strain gage activity on the transition pieces was 80–90% of the activity recorded when standard combustion hardware was used. The transition piece vibratory displacements were 20–30% of baseline experience.

Engine performance and emissions with the multinozzle system were comparable to those of the baseline system, except that the multinozzle system required about 30% higher water injection rates to meet NO_x emissions standards.

For the entire endurance run the unit used natural gas fuel. Baseline tests and engineering tests with the multinozzle system indicate that oil firing would not produce materially different dynamic pressure results. The multinozzle system, however, had some difficulty achieving ignition with oil, and a commercial offering would have to provide a design modification to remedy this condition.

Future commercialization of this technology will depend on the price of commercially produced hardware and the savings that utilities can project from its use. *Project Manager: Henry Schreiber*

HEBER GEOTHERMAL BINARY PROJECT

The potential of the moderate-temperature geothermal resources already identified in the United States is approximately 10,000 MW (e). Because of the size of the resource base and the projected economic advantage of using binary-cycle technology to recover this energy, efforts are under way in industry, EPRI, and the federal government to develop the technology for commercial application. The purpose of the $122 million, 45-MW (net) Heber binary project is to scale up the existing binary-cycle technology and to demonstrate its performance capability, economic competitiveness, and environmental acceptability at a commercial size. The project builds on the experience gained from earlier EPRI geothermal studies and field experiments. The results and experience obtained from this project will provide the basis for future development of moderate-temperature geothermal resources for electric power generation.

Power plant construction

San Diego Gas & Electric Co. (SDG&E) is the host utility and the project manager. The project started in September 1980, and the site construction effort, which began on June 16, 1983, is now over 60% complete. A visitor's first impression when looking at the plant is its low profile: the 55-ft (17-m) cooling tower is the highest structure at the site except for the flare stack (Figure 3). This is in sharp contrast to a conventional fossil fuel plant whose boiler might rise 200 ft (61 m) or more above the site grade. Also unusual for a power plant are the eight brine-hydrocarbon heat exchangers—10 ft (3 m) in diameter and 78 ft (24 m) long—installed on concrete support pedestals and a hydrocarbon storage sphere 44 ft (13.5 m) in diameter. The plant's electric cables (power, control, and data transmission) are all underground. The large-diameter (30, 42, and 60 in; 76, 107, and 152 cm) piping is mostly aboveground. These transport the 7.9 million lb/h (17,800 gal/min; 1.13 m^3/s) of geothermal brine and the 8.3 million lb/h (30,000 gal/min; 1.90 m^3/s) of hydrocarbon working fluid (a mixture of 90% isobutane and 10% isopentane) through the plant.

Both the brine-hydrocarbon heat exchangers and the hydrocarbon condensers are shell-and-tube designs. Because of the chemical properties of the geothermal brine and the cooling water, both the heat exchanger tubes and the condenser tubes are made from ferritic stainless steels, AL 29-4C for the former and Sea-Cure for the latter. These alloys of chrome, molybdenum, and nickel increase the tubes' resistance to corrosion.

The brine production island is adjacent to the plant site along the north property line. Here, Chevron Geothermal Co. has been drilling since December 1983, and five wells have been completed thus far; eight more are planned. The contract with Chevron calls for first delivery of the hot brine (360°F; 182°C) from the production island to the power plant in January 1985. After the heat is extracted, the

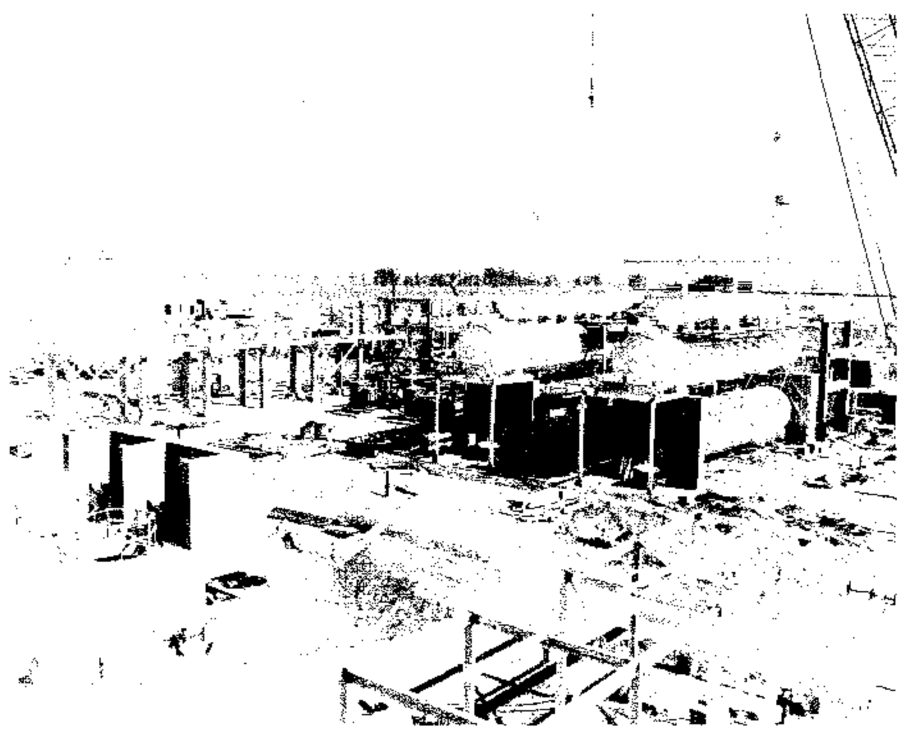


Figure 3 Two prominent features of this low-silhouette plant are the 44-ft (13.4-m) diameter hydrocarbon storage sphere on the left and the two parallel hydrocarbon condenser installations on the right. The fluid coming from the turbine exhaust enters the distribution header (top), goes into the condenser (middle), and collects in the reservoir (bottom). At any given time during operation, most of the hydrocarbon inventory will be in these tanks; the storage sphere is used when the plant is shut down.

cool brine (160°F; 71°C) will be returned to Chevron for reinjection into the reservoir formation at the edge of the main reservoir about 1.5 mi (2.4 km) northwest of the plant site. Downwell pumps will be used to maintain the high flow rates and pressures necessary to prevent the brine from flashing either in the well or in the plant. Maintaining pressure on the fluid is expected to reduce scale deposition by preventing the gases and minerals in the saturated brine from coming out of solution.

Design aspects

One of the unique features of this binary-cycle power plant is the 70-MW (gross) hydrocarbon turbine. Although within the present state of the art in turbine design, this turbine is a significant scale-up from those previously built and operated.

Early EPRI studies evaluated turbine and working fluid alternatives and developed a preliminary design for the axial-flow turbine that was selected for this project. The tubine's small size—7.5 ft (2.3 m) in diameter and 13 ft (4 m) long—is surprising to those accustomed to conventional steam turbines. The double-flow, three-stage turbine has inlet conditions of 305°F (152°C) and 575 psia (4 MPa). It should have an overall efficiency in the upper 80% range; exact performance will be measured during the startup and demonstration phases.

Analogous to a conventional fossil fuel boiler, this plant has two parallel heat exchanger trains, each with four brine-hydrocarbon heat exchangers in series. These transfer the thermal energy from the geothermal brine to the hydrocarbon working fluid. Although utilities are accustomed to handling flammable materials (e.g., fuel, lubricants) at a power plant, documenting the experience with the hydrocarbon working fluid will provide valuable knowledge and enhance the subsequent acceptance of this technology by the utility industry.

The data requirements of this large-scale demonstration project necessitate the processing of larger amounts of information than is normal at a commercial power plant. A distributed digital control and data collection system will handle these increased data requirements and the plant's control needs. As this will be the first digital control installation on the SDG&E system, designers of the control room elected to use both color-graphic displays and conventional control panels with switches, dials, and controls to support plant operation.

Based on exploratory wells drilled in the early 1970s, the Heber reservoir is thought to have a proven reserve that could be produced at the rate of 500 MW (e) for 30 years. The production wells are being slant-drilled from the production island to depths ranging 4000–10,000 ft (1220–3050 m). The desired spacing at the bottom of the wells will be achieved by both vertical and lateral displacement as much as 2000 ft (610 m). This approach (as opposed to spreading the wells over a significant surface area and piping the brine from individual wells to the production site) will minimize drilling cost and land use. The surface land is farmed intensively, and the alternative approach would have removed a larger land area from production.

The designers of this plant assumed that the brine temperature would drop by as much as 30°F (17°C) over the project's lifetime; this was also taken into account when estimating reservoir capacity. Because the plant is rated under end-of-run conditions, there will be some excess heat exchanger capacity at the beginning of the run.

Studies showed that manning the plant with SDG&E supervisory personnel and a contracted operation and maintenance staff would be the most economic approach. On the basis of this finding, the project has contracted with a service organization to operate and maintain the plant. Two flashed-steam geothermal pilot plants (10–12 MW) in the same general area have used this approach with satisfactory results.

Another unique aspect of this plant's design is its application of a floating cooling concept. The plant's cooling system (tower, piping, pumps, and condensers) will run at its rated capability throughout the year; therefore, the plant's electric generation capacity will vary, depending on the surrounding wet-bulb temperature. Computer simulation studies for this application have shown that the floating cooling method results in a higher annual kilowatthour production than would a conventional approach.

Plant startup

Brine is first scheduled for delivery from the production island to the plant in mid January 1985 at the rate of 600,000 lb/h (1355 gal/min; 0.085 m^3/s). This will rise in discrete steps to the rated level of 7.9 million lb/h (17,900 gal/min; 1.13 m^3) sometime between January and April 1986.

Demonstration

After startup is complete, a two-year demonstration phase is planned. This will enable personnel to fully evaluate all data and experience from the project. One early objective of the project is to provide the information base necessary to support decisions concerning further commercial application of this technology. The emphasis will be on the development of data in three areas.

- System and subsystem performance, including acceptance, operation, and long-term testing, to confirm predicted performance capability
- Environmental acceptability, including the short- and long-term effects of plant operations in light of present environmental regulations
- Economic and financial factors, including identification of nonrecurring costs unique to the demonstration aspects of the project and the documentation of costs for construction, operation, and maintenance that would apply to subsequent commercial binary-cycle geothermal power plants

Test plan

Test planning for the project's startup and demonstration phases is well under way. Two of the major objectives of this effort are to ensure thorough testing and development of data sufficient to support near-term and long-term evaluation.

Several organizations will participate in the data evaluation and documentation under contracts with DOE and EPRI.

- Lawrence Berkeley Laboratory—evaluation of thermodynamic performance of the system
- Energy Technology Engineering Center—evaluation of overall performance, both technical and economic
- Technicon Corp.—evaluation of economics of the system and projection for a commercial binary-cycle geothermal power plant
- Battelle, Northwest Laboratories—evaluation of material chemistry and corrosion impact
- Burns & McDonnell Engineering Co.—documentation of lessons learned during design, construction, startup, and early operation

In addition, EPRI plans to publish an index with abstracts of all documentation and reports produced by and available from the project. This central index will be valuable to other organizations desiring information on this project.

Binary-cycle technology shows great promise for significantly opening up the geothermal resource base in the western United States. The Heber project will provide the utility industry with the proving ground for this new geothermal power system capability. *Project Manager: J. E. Bigger*

R&D Status Report
COAL COMBUSTION SYSTEMS DIVISION

Kurt Yeager, Vice President

20-MW (e) AFBC PILOT PLANT

Atmospheric fluidized-bed combustion (AFBC) is an improvement in coal-fired boiler design that offers several advantages over conventional boilers. AFBC can meet sulfur and nitrogen oxide emission regulations without the need for add-on flue gas treatment equipment. The relatively low combustion temperature—about 1500°F (815°C), as opposed to about 2500°F (1400°C) for pulverized-coal boilers—inhibits ash melting, thus reducing slagging and fouling, which can, in turn, increase a boiler's fuel flexibility. Owners of small boilers have begun to accept AFBC over the last 10 years. However, designs established for these relatively small power needs cannot be directly scaled up to sizes required for utility power generation. Part of EPRI's AFBC program addresses the scale-up issues by scheduling progressively larger test units: a 2-MW development unit, a 20-MW pilot plant, and commercial-size demonstrations with 100–160-MW units. This report discusses progress at the 20-MW pilot plant built by TVA at its Shawnee power station near Paducah, Kentucky.

The fluidized-bed boiler that operates at near-atmospheric pressure on the fire side is relatively simple and no different in purpose from those pulverized-coal boilers used by utilities today. Fluidized-bed boilers can generate steam at the pressure and temperature needed by modern steam turbines; only the firing system is different.

In fluidized-bed combustion, the fuel (which can be almost any coal or waste fuel) is burned at 1500–1600°F (815–870°C). Air is forced through the bed at 4–12 ft/s (1.2–3.7 m/s), a velocity sufficient to support the weight of the bed particles. When the bed is fully fluidized, it bubbles like a boiling liquid. Although the burning coal makes up less than 1% of the fluidized bed, all the bed particles are heated quickly by the turbulence.

Boiler tubes submerged in the bed absorb heat directly from the turbulent solids. The heat converts water in the tubes to steam or superheats the steam. Because of the intimate contact of the boiler tubes with the fluidized bed, heat transfer is highly efficient and, consequently, less boiler tubing surface is needed to generate the same amount of steam as in a comparable pulverized-coal boiler. The high heat transfer rates also permit lower combustion temperatures, resulting in the formation of relatively low levels of NO_x. Because operating temperatures are below those that fuse coal ash, a single design can burn a variety of coals.

AFBC scale-up

When EPRI initiated its research program in the mid 1970s, little AFBC design information existed that was specific to utility applications. A 30-MW AFBC was commissioned by DOE at Monongahela Power Co.'s Rivesville station, and its operation highlighted some of the critical issues for utility application. To help address these problems, EPRI built a 2-MW AFBC process development facility at Babcock & Wilcox Co.'s Alliance (Ohio) Research Center in 1977.

The 6 × 6-ft fluidized-bed cross section and the unit's high freeboard (the furnace space above the bed) were selected to simulate the large bed area and long residence time that typify utility units. A testing program resulted in design modifications for improving the process to meet utility efficiency requirements.

In 1979 TVA and EPRI developed plans for a 20-MW AFBC pilot plant, a tenfold scale-up over the 2-MW, 6 × 6 facility (Figure 1). This engineering pilot unit, located at TVA's Shawnee steam plant, was designed to simulate utility power plant operating conditions and mechanical features. TVA completed construction of the pilot plant in May 1982.

Following startup, TVA and EPRI initiated a four-year test program to verify process performance achieved at the smaller 6 × 6 facility, to test full-scale components, and to establish turndown and control philosophies for utility application.

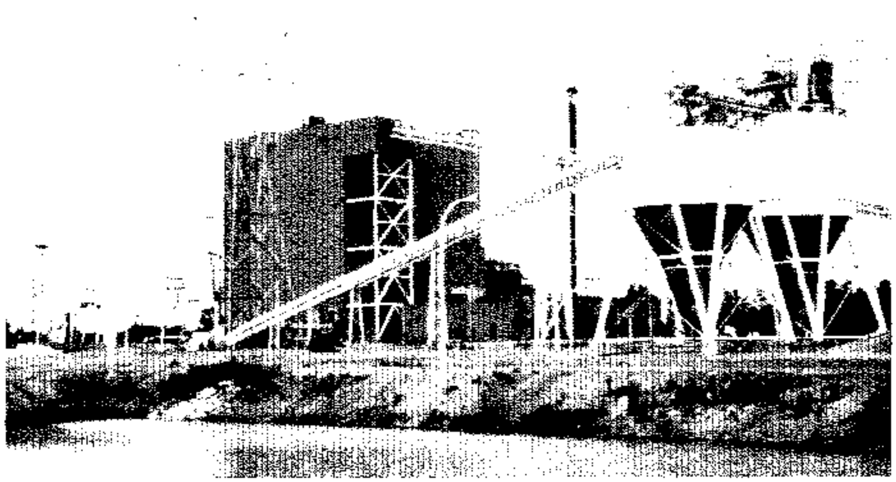


Figure 1 The TVA 20-MW (e) AFBC pilot plant is located west of Paducah, Kentucky, adjacent to TVA's 1000-MW (e) Shawnee power plant. The facility is self-contained; coal unloading and handling facilities are shown in the foreground.

The first coal fire occurred in May 1982 and a full-load 24-hour operability test run was achieved soon after. The formal TVA–EPRI test program started in July, following 300 hours of hot function checks. The initial test campaign lasted until April 1983 and accomplished the objectives of operator familiarization, equipment shakedown, data acquisition implementation, and base case performance testing. The unit operated approximately 1500 hours during this period. Following the shakedown, testing began to evaluate system performance and unit operating characteristics, using the two alternative methods of feeding coal and limestone (underbed and overbed). At the end of May 1984, the unit had run approximately 6800 hours.

Coal feeding

A major objective of the 20-MW test program is to develop the technical basis for the design of coal-feeding systems for utility AFBC plants. Options available for testing at the 20-MW plant include feeding the coal underbed at the air distributor elevation and spreading it over the top of the bed. The knowledge gained on the 20-MW, where one coal type is tested, is being extended on the 6 × 6 by combusting a range of coal types in both feeding modes. Results show that the preferred feeding method could depend on the basic coal type being considered.

In the underbed method, coal is crushed to about ¼-in top size and prepared for pneumatic transport. At the 20-MW pilot plant, the coal is metered by standard gravimetric feeders through a well-tested pressure locking device (a coal pump) into a pneumatic transport system. The coal is carried in pneumatic transport lines toward the bottom of the fluidized bed and is divided into a number of streams just before it is swept up into the fluidized bed.

Overbed feeding uses spreader-stokers that throw the coal over the top of the bed, where the furnace pressure is neutral. Coal for overbed feeding is crushed to about 1¼-in top size.

Over 3800 hours of testing have been completed with the underbed feed system at the 20-MW unit, using unwashed Kentucky No. 9 coal. In the original configuration, the coal pumps and feed lines in the system were sensitive to plugging because of the moisture in large particles. Also, erosion caused feed line failures and required the replacement of the coal pump internal parts. Although several improvements have since been made to the existing underbed system and are now being tested, project personnel are also considering alternative designs. These alternatives integrate the various basic requirements of an underbed system: coal sizing, drying, and sealing against the pneumatic pressure required to overcome the pressure at the base of the fluidized bed.

The overbed spreader-stoker system presents a less-complex feeding system. This system does not require extensive coal sizing and drying. Further, the feeding system itself has been far more reliable than an underbed system on the 20-MW unit. However, testing the unwashed Kentucky No. 9 coal shows some limitations: an inability to deal with variable coal fines (>10% of the coal particles less than 30 mesh) and the accumulation of ash particles in the bed that are too large to fluidize. Tests of Northern States Power Co.'s western subbituminous coal show that these limitations may be specific to the type of coal and its combustion characteristics. Western coal was successfully burned in the overbed feed mode at the 6 × 6 without problems of ash accumulation. As a result, an overbed feed system was selected for the 125-MW retrofit demonstration at Northern States Power.

For the Kentucky No. 9 coal, solution to the overbed feeding problems may require some coal preprocessing to normalize and reduce the amount of fines and to remove the rocks from the coal, which could add significantly to the cost of such a system. Alternatives being investigated for the rock problem are development of a rock removal system within the fluidized bed and firing smaller top-size coal. Once fines are controlled to 10% less than 30 mesh, process performance approaches that for underbed feeding.

Investigators continue to evaluate feed system performance and reliability at both the 20-MW and the 6 × 6 test facilities. These studies will enhance the design of both systems for demonstration. The economic impact and trade-offs between capital cost, operating cost, and expected availability will be the basis for selection.

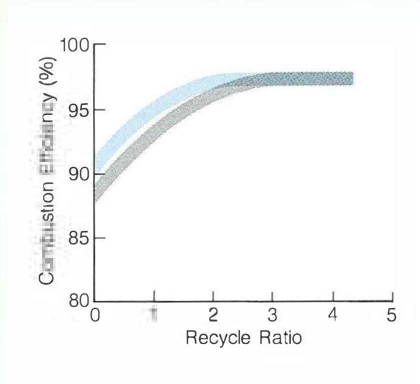
Combustion efficiency and emissions control

In any process, carbon combustion is directly proportional to the amount of time the particle has to burn. In a fluidized bed the parameters that affect this residence time are gas velocity, bed depth, freeboard height, and recycle ratio (ratio of fine char reinjection rate to coal feed rate). AFBC tests have focused on the effects of recycle rate while maintaining near-constant bed depth, temperature, and velocity.

Figure 2 shows combustion efficiency versus recycle ratio for the underbed and overbed tests with the Kentucky No. 9 coal. Comparison of the two curves shows that the unit performance is comparable for underbed feed and overbed feed with washed coal. (Washed coal was used to control ash and the percent fines.) Efficiencies of over 97% have been attained with both feed systems at recycle ratios between 2 and 2.5. Combustion efficiency drops considerably for unprepared coal fed over the bed. In contrast to the Northern States Power coal tests at the 6 × 6, combustion efficiencies in excess of 99% were achieved with both feeding methods at a recycle ratio of 1.5.

Carbon losses for either feed system are almost completely contained in the char (multiclone disposal) and fly ash (baghouse catch). As the recycle rate increases, more particles escape the multiclone, and the fly ash rate increases. In addition, less multiclone catch is sent to disposal. The percent carbon in each stream will drop because of the increase in total residence time, although the amount of fly ash decreases only slightly. Figure 3 shows the

Figure 2 Combustion efficiency increases when the char recycle ratio (mass flow ratio of char to coal feed) is increased. At recycle ratios of 2.5/1 and higher, the combustion efficiency is the same for overbed (gray) and underbed (color) methods.



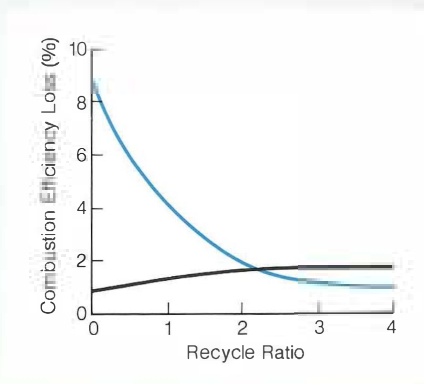


Figure 3 Sources of combustion efficiency loss are primarily carbon particles contained in the multiclone (which is the source of the char recycle) and the baghouse. These curves show the dramatic effect of recycle on reducing the losses in the multiclone catch (color) at the expense of a slight increase in the baghouse catch loss (gray).

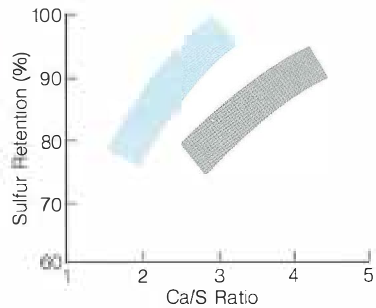
net effect of recycle on combustion efficiency for underbed feed as it is reflected in each waste stream.

SO_2 capture in a fluidized-bed boiler depends primarily on the amount of sorbent (limestone) in the boiler, sorbent surface area, and sorbent residence time in the unit during which reactions can take place. Operating parameters that control these factors are the calcium/sulfur (Ca/S) mole ratio, char recycle, bed depth, temperature, freeboard height, and gas velocity. AFBC tests have investigated the effects of Ca/S mole ratio and char recycle on sulfur capture while maintaining near-constant bed depth, temperature, and superficial velocity.

Obviously, changes in the Ca/S mole ratio have the greatest effect on overall SO_2 retention. Increasing or decreasing the fresh sorbent addition rate will affect the SO_2 emissions level almost immediately. Economically, the least amount of limestone must be used; hence the Ca/S mole ratio is kept as low as possible. Therefore, the best option for lowering SO_2 emission is to recycle the unsulfated sorbent that would be lost to disposal. Recycling gives the sorbent particles more time to react.

Figure 4 shows SO_2 retention plotted against Ca/S with Kentucky No. 9 coal for char (multiclone catch) recycle ratios of 2–2.5 for the underbed and overbed feed tests. These results indicate that 90% retention can be reached with underbed feed having a Ca/S ratio of 2.2 to 2.8. The overbed results with prepared coal show the same trend; however, the Ca/S requirements to meet 90% sulfur capture are considerably higher.

Figure 4 The target of 90% sulfur capture is achieved at lower Ca/S ratios for underbed feed (color) than for overbed feed (gray).



Materials

One concern about AFBC use is corrosion/erosion of tubes immersed in the fluidized bed and erosion of convection pass surfaces. To inhibit corrosion, researchers have developed tube material selection criteria for evaporative, superheater, and reheater surfaces. The data base, however, is restricted to small test units in which tests have rarely exceeded 2000 hours. Extensive monitoring at the 20-MW and 6 × 6 facilities will add to this data base. Results of 7000 hours of testing at the 20-MW facility and 12,000 hours at the 6 × 6 facility have confirmed the results from the smaller test rigs.

Erosion of in-bed tubes has been reported at the 6 × 6 and 20-MW units. In all cases, the erosion has primarily been localized—caused by such factors as jetting from underbed feed nozzles and air distributors or from flow stratification caused by nonuniform tube geometries. Periodic measurements and inspections are continuing at the 20-MW facility. A data base of these incidents is being compiled and will culminate in fluidized-bed design guidelines.

Effect of scale on performance

Although demonstrated performance from pilot facilities can indicate developmental status and performance shortfalls, confidently scaling up the results to large unit designs is the true indication of overall technologic status. Such confidence has been enhanced recently by comparing test results from the TVA 20-MW pilot plant and the EPRI–B&W 6 × 6 test facility. Preliminary results from these investigations have shown the following.

- Results from small (6 × 6) pilot plant to large (20-MW) pilot plant have been verified.
- Scale variables between the two facilities for use in the next size scale-up have been isolated.
- Scaling effects, particularly in the freeboard, are favorable from a performance perspective.

Investigators believe that the effects of increased scale will overcome performance shortfalls between current pilot results and utility design requirements. Several geometric differences and other parameters allow review of data from the two facilities on the basis of scale. The parameters that affect process performance are feed point spacing, recycle point spacing, freeboard height, freeboard design, and recycle cyclone efficiency.

Isolation of each of these variables' effects at the two pilot plant scales will enable personnel to confidently predict the performance at larger scale. These parameters require analyses of data from the two facilities that isolate fluidized-bed performance and freeboard performance. It should be noted that increased freeboard residence time and turbulence are natural consequences of scale.

Comparison of the overbed and underbed feeding methods, which emphasized coal feed point and recycle feed point spacing effects on performance and subsequent scale comparisons with the 6 × 6 unit, was completed in May 1984. Current tests focus on turndown and load following.

Plans after mid 1984 include further verification of design features for the TVA and Northern States Power demonstration projects, combustion of different fuels and sorbents, and testing of alternative systems/components for ultimate design optimization. *Project Managers: William Howe and Thomas Boyd*

R&D Status Report
ELECTRICAL SYSTEMS DIVISION

John J. Dougherty, Vice President

PLANT ELECTRICAL SYSTEMS AND EQUIPMENT

Torsional vibration monitoring

Significant disturbances on transmission systems can result in damaging mechanical shock to the turbine generator. A massive incident or an accumulation of many, less-damaging events can lead to a catastrophic failure of the entire turbine generator set. To forestall such failure, EPRI initiated a project to monitor the torsional vibration of turbine generators and to relate this to system events (RP1746).

In the last two phases of the project, torsional vibration monitoring systems (TVMS) installed in several power plants are capturing data on the interaction between system and machine. After each event, the data analysis is returned to the power plant. Engineers are using the accumulated data from all TVMS installations to provide an overall assessment of system operations and machine design (Figure 1). The prototype monitor installed at the Mohave power plant has provided key data to Southern California Edison Co. and enabled the utility to refine its system operating procedures.

A users group has been formed for those utilities that are participating in this project. The group, which held its first meeting in June 1984, will meet on an annual basis to discuss the operation and use of the TVMS hardware equipment, as well as to contribute information and suggestions to the EPRI project.

Seven users have installed the TVMS equipment developed in Phase 1 of this project and are monitoring 12 turbine generators. Although several more users will be participating in this project in the near future, EPRI is requesting participation by additional utilities to help improve the overall data base from which the final project conclusions will be drawn. A videotape (Tech Tape) is available that explains the project and the TVMS equipment. *Project Manager: J. S. Edmonds*

POWER SYSTEM PLANNING AND OPERATIONS

Near-term enhancements to EGEAS

The first phase of RP1529 involved the development of EGEAS (electric generation expansion analysis system), a computer program to aid utility planners in carrying out the three primary analysis functions in generation planning: optimal generation expansion, reliability analysis, and production cost calculations (*EPRI Journal,* May 1982). EGEAS, which contains basic solution techniques and models for developing generation expansion alternatives, operates from a single, consistent data base.

EPRI shared the capabilities of EGEAS and

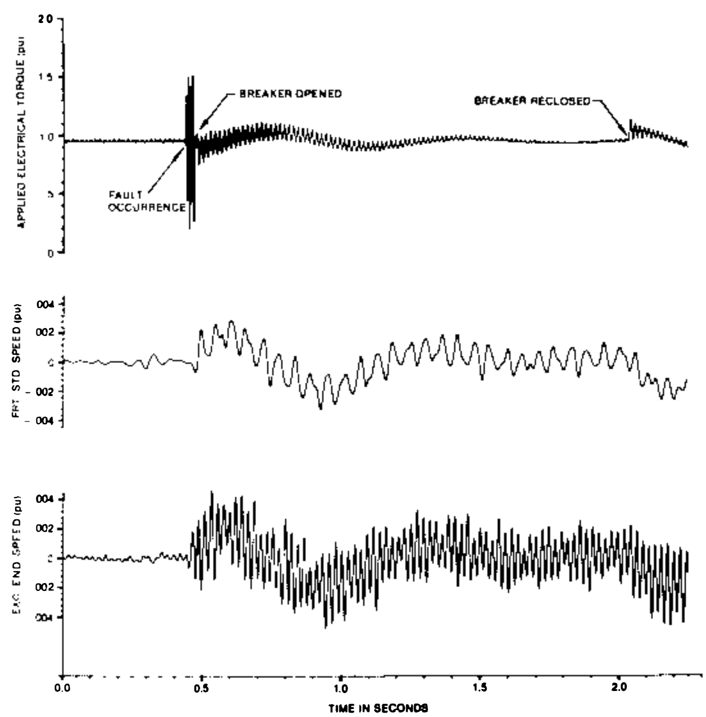


Figure 1 Utility engineers can use the data accumulated from the event reports to make an in-depth assessment of system operation. The data can be permanently stored in a data base restricted to the TVMS owner.

the utility demonstration test results with over 80 utility representatives at two seminars held in early 1983. EPRI then distributed EGEAS to over 50 member utilities, and an EGEAS users group formed in September 1983.

Industry representatives recommended numerous modifications and enhancements to EGEAS that would produce a computer program having still greater use and wider applications in the utility industry. Responding to these needs, EPRI initiated Phase 2 of the project with Stone & Webster Engineering Corp. in September 1983 (RP1529-2).

The objective of Phase 2 is to develop and include the several enhancements in the EGEAS program.

- A model for economic utilization of storage units
- A model for must-run units and spinning reserve requirements
- Modifications to the dynamic programming optimization option, including a restart feature and file-merging capability
- Improvements to the generalized Bender's decomposition optimization option to allow hydro and storage units as alternatives and to implement maintenance scheduling
- Inclusion of incremental cost information in the production cost module
- Expansion of the capabilities of the report generator program to provide information on loading order, maintenance schedules, storage units, and neighboring system characteristics

These enhancements are scheduled for completion by June 1985, and a revised version of EGEAS, with documentation, should be available through the Electric Power Software Center by August 1985. *Project Manager: Neal J. Balu*

DISTRIBUTION

Oilless distribution transformer

The oil-insulated distribution transformers in common use today are subject to destructive failure when arcing occurs under the oil. The rapid rise in pressure can result in tank or bushing failure and the subsequent explosion of hot or burning oil from the tank. This project is an attempt to address the problem by eliminating the oil that causes the rapid pressure rise (RP1143).

Because the oil in these transformers transfers heat and provides electric insulation, alternative designs must also perform these functions. The design developed uses all-inorganic materials for insulation; this allows the transformer coils to run hot enough for cooling (primarily by radiation to the tank) and thus controls transformer losses and tank temperatures. The design also uses a winding configuration quite different from a conventional transformer. Instead of conventional concentrically wound sheet and wire conductors, this transformer uses strip conductors wound in flat pancake fashion and stacked together around the core. An inorganic tube around the core and inorganic spacers between the pancake coil sections provide the required insulation. The turn-to-turn insulation is also made of inorganic materials.

To date, over 60 experimental transformers of various designs have been built, and a design has been selected for initial field trials. Although this design is not yet optimized, much can be learned from field trials while design work continues. This design has successfully passed short-circuit, load-cycling, mechanical, and other required tests. The basic insulation level was not as high as for an oil-filled unit, but it should be adequate if the transformer is used with modern gapless arresters.

Twenty transformers of the 15-kV, 25-kVA class have been built and are being shipped to various utilities for a one-year trial period. Figure 2 shows a cutaway of one of these transformers. Completion of the project is expected at the end of 1986. *Project Manager: Joseph Porter*

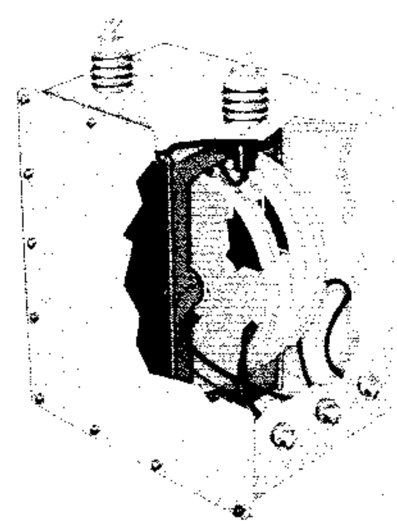


Figure 2 A cutaway of the 15-kV, 25-kVA oilless distribution transformer shows its pancake coil configuration. The enclosure measures 30 in (76.2 cm) wide, 36 in (91.4 cm) tall, and 16 in (40.6 cm) deep.

TRANSMISSION SUBSTATIONS

Amorphous metal core power transformers

A previous project determined that an economic force exists for the application of amorphous metal cores in power transformers (RP1290-1, -2). This driving force is based on the total cost of owning the transformer; the selling price plus the present worth of the losses incurred by the transformer throughout its life determines the capital expenditure. Amorphous metal holds promise of reduced lifetime losses (no-load losses that are one-third those of conventional magnetic iron).

Larger power transformers, however, use a stacked core configuration rather than a toroidal or wound core. Stacking individual thin sheets (1–1.5 mils) of amorphous metal does not appear to be a practical application of this new material.

Consequently, EPRI is pursuing three alternative approaches: casting amorphous material that is 5–10 mils thick and 5.8 in (14.7 cm) wide (RP1290-3); bonding material that is 1 mil thick and probably 8 in (20.3 cm) wide into an optimal total thickness (somewhere between 5 and 25 mils) under pressure and heat but retaining amorphous state with satisfactory losses and exciting current (RP2236-1); or stacking 1.5-mil-thick cast material several sheets at a time (RP2236-2). After satisfactory exploration of these three approaches, the most economic and expeditious procedure will be chosen. *Project Manager: Edward T. Norton*

UNDERGROUND TRANSMISSION

Computerized data base on dielectric materials

With the prolific development in recent years of numerous classes of synthetic materials, many with important dielectric properties, the resultant literature has become too voluminous for a user to thoroughly read and critically analyze. A service that provides the designer and researcher with reliable, up-to-date information on dielectric materials would be invaluable. It would reduce design cycles, help prevent the duplication of effort, and aid in the selection of the most cost-effective materials.

The best system currently available to store and manipulate the large amounts of data that such an information service would require is the electronic data processor. Current work on data processing systems is drastically reducing storage costs, improving processing speeds and versatility, and simplifying the language requirements for system users.

Of paramount importance in any information service is that the data be absolutely reliable. The objective of this project is to develop just such a data base (RP7897-5). The data base ultimately will provide technical and commercial information on all dielectric materials: solids, liquids, gases, and combinations of these.

A number of data categories will be available.

- Material specification and characteristics
- Physical properties
- Electric and dielectric properties
- Thermal properties
- Chemical properties
- Optical and thermoradiative properties
- Mechanical properties
- Flammability properties and information
- Health hazard and environmental impact information
- Processibility and manufacturing technology
- Aging, degradation, erosion, and corrosion information
- Usefulness and application information
- Producers and suppliers
- Availability and price range

Access to the database, at the user's option, will range from written or telephoned requests to direct and interactive access from the user's computer terminal via telephone lines. Users will be able to extract data in whatever format they desire, tabular or graphic, and in whatever units they prefer.

The initial phase of this project is the development of a pilot data base; although reduced in size, it will be sufficient for testing the operation of such a system. This effort, conducted by the CINDAS group (Center for Information and Numerical Data Analysis and Synthesis at Purdue University), is limited to dielectric liquids. To date, the CINDAS group has identified over 200 dielectric liquids, as well as more than 120 properties and variables.

Testing and a critique of the pilot data base by a cross section of utility and industrial users will commence later this year. *Project Manager: Felipe G. Garcia*

Extruded insulation research

Transmission cable systems employing extruded dielectrics, particularly cross-linked polyethylene and ethylene-propylene rubber, have become an increasingly popular option for utilities. This is due largely to the avowed properties or features used to market these materials when they were introduced to the industry.

- High emergency temperature ratings
- Resistance to moisture degradation
- Less-demanding splicing and terminating procedures and skill requirements
- Essentially unlimited life

However, an unfortunate service history, albeit mostly at distribution voltage levels, has raised serious questions on whether extruded cable can live up to expectations.

This undesirable service history has spurred a great deal of R&D in the last 10 years to address the real or potential problems in extruded dielectric systems, such as the mechanism of aging; mechanism of failure; treeing phenomena; effects of moisture, voids, and contaminants; stress effects; temperature effects; threshold voltage existence/determination; discharge detection; factory and field test procedures; environmental and workmanship requirements for accessories; and thermomechanical effects and considerations. EPRI, DOE, and both domestic and overseas manufacturers, users, and institutions have supported this work.

The conclusions drawn are largely available; however, the references are extensive, some of the work appears flawed, contradictions abound, and service history does not always match laboratory work. These discrepancies are the product of inadequate test techniques and differences in test conditions, the nature and treatment of samples, and the number and age of samples.

To continue intelligent research in this area, a resolution of differing research results with appropriate recommendations is in order. Some time ago EPRI contracted a technical planning study with Underground Systems, Inc. (TPS 82-631). The general scope includes a literature search, an effort to categorize conclusions and resolve conflicts, and preparation of a concise summary of the state of the art. The study will produce a list of recommendations for changes in current specifications, procedures, or practices, with referenced bases for recommendations, and will provide user incentives and disincentives for implementing such changes. A list of recommendations for future research, the anticipated benefits of this research, and the order of priority of such work will also result. This summary document should be available late this year. *Project Manager: John Shimshock*

R&D Status Report
ENERGY ANALYSIS AND ENVIRONMENT DIVISION

René Malès, Vice President

WEATHER NORMALIZATION OF SALES

In most electric utility service areas, weather exerts a strong influence on customer electricity use. For a variety of reasons, utilities have to know if recorded customer use would have been different under normal weather conditions and, if so, how different. Utility management, along with creditors and investors, find this information useful as part of the routine evaluation of corporate performance. Regulatory agencies often require the information in support of utility applications for weather-related revenue adjustments, and utility management can use it in explaining variations in bills to customers. Also, electricity use data that have been adjusted for weather effects (weather-normalized use data) are necessary for long- and short-term load forecasting. In RP1922, summarized here and documented in EPRI EA-3143, researchers examined the influence of weather on monthly energy sales for residential and commercial customers. Other EPRI projects have considered the effect of weather on hourly load curves and peak demand (RP1008, reported in EA-1672, Vols. 1–5; and RP1955, reported in EA-3698, Vols. 1–3, forthcoming).

Case studies

In the early phase of RP1922, about 40 utilities were surveyed to identify the methods currently used for weather normalization and to assess the main issues in this project. The utilities identified three major concerns: matching daily weather data to billed sales data; identifying the nonlinear relationship between sales and weather; and dealing with the lack of accurate data on factors that influence the sensitivity of electricity use to weather—for example, appliance holdings and building characteristics.

The project personnel addressed these and numerous other issues through case studies. They obtained data from four utilities that represent a diversity of geographic locations, weather conditions, sales levels, and seasonal peaking characteristics: Georgia Power Co., Northeast Utilities, Puget Sound Power & Light Co., and Union Electric Co. For each utility, models for the weather normalization of residential and commercial sales were estimated and tested for a variety of conditions. The results on residential sales are summarized in Table 1.

A new procedure for matching weather data to sales data was developed. Weather variables associated with each month's billed sales were calculated as weighted averages of daily weather over the current month and the previous month; each day's weight was proportional to the number of customers whose consumption on that day was included in the billed sales.

Using new methods developed in the project for assessing model accuracy, the researchers found that when weather variables are calculated in this way, very precise weather normalization models result. In fact, the models perform well despite the lack of data on factors affecting weather sensitivity, such as appliance holdings, electricity prices, and customer incomes. The important component of weather normalization seems to be the accurate calculation of weather variables, not the inclusion of nonweather variables. This procedure, which requires only that the utility use available data on the number of customers by billing cycle, represents a considerable advance over the earlier practice of using weather variables from previous months.

The researchers also developed a procedure for identifying the shape of the response curve relating weather to sales. The procedure, called nonparametric estimation, is very powerful in identifying any nonlinearities that may be present in the weather-sales relationship. It detects nonlinearities and appears to be an advance over the practice of estimating piecewise linear curves through trial and error.

Regarding the lack of data on factors conditioning weather sensitivity, perhaps the most important project finding is that this lack is not debilitating to the models. Very accurate models of weather normalization can generally be obtained even without high-quality data on nonweather variables. A second conclusion is

Table 1
SENSITIVITY OF RESIDENTIAL ELECTRICITY SALES TO WEATHER
(kWh per customer)

Utility	Sales per Heating Degree-Day	Sales per Cooling Degree-Day	Sales per Unit of Discomfort Index	Mean Monthly Sales
Union Electric Co.				
St. Louis city	0.204	0.917	4.64	460
St. Louis county	0.424	1.610	10.30	804
Remainder	0.765	0.826	12.90	897
Georgia Power Co.	0.489	1.140	—	858
Northeast Utilities	0.120	0.819	—	482
Puget Sound Power & Light Co.	0.282	—	—	1136

Note: Both the heating degree-day and the cooling degree-day have a base of 65°F (18°C). The discomfort index is a measure that combines temperature and humidity.

that when conditioning factors change in such a way that weather sensitivity varies significantly over time, models incorporating time-varying parameters are substantially better at normalizing sales accurately than models with fixed parameters. The project developed a test for determining if weather sensitivity in a given utility's territory has changed over time. This new procedure permits the measurement of changes in weather sensitivity not previously observable.

If the test indicates that weather sensitivity has not changed significantly, then standard models with fixed parameters are appropriate. In fact, in such cases models based on time-varying parameters can give unreasonable results. If weather sensitivity has changed, however, models with time-varying parameters can be very beneficial. The project developed and applied procedures for estimating such models; Figure 1 compares case study results from models with and without time-varying parameters.

WENS methodology

A software package called WENS (weather normalization of sales) has been developed to help utilities estimate models for weather-normalizing monthly sales. The methodology entails the following steps.

The utility applies the nonparametric procedure to identify the shape of the response curve relating weather to sales. By examining this response curve, the utility then identifies the number and location of breakpoints that a piecewise linear function would need and defines degree-day variables with base temperatures at these breakpoints. Next, appropriate weather variables are constructed for each month. A regression model of sales per customer is then estimated on these monthly weather variables. Using the residuals from the estimated model, the utility tests the hypothesis that weather sensitivity has been constant over time. If the hypothesis is not rejected, the model is considered appropriate for use in weather normalization. If the hypothesis is rejected, the utility estimates a model with time-varying parameters.

It is important to note that this procedure is intended to aid utility personnel in developing accurate weather normalization models, not to limit their choice of methods. The results from RP1922 are presented in detail in EA-3143. The methodology developed for estimating models with time-varying parameters is being used extensively in another EPRI project (RP2279), which is addressing short-run forecasting models. *Project Manager: Ahmad Faruqui*

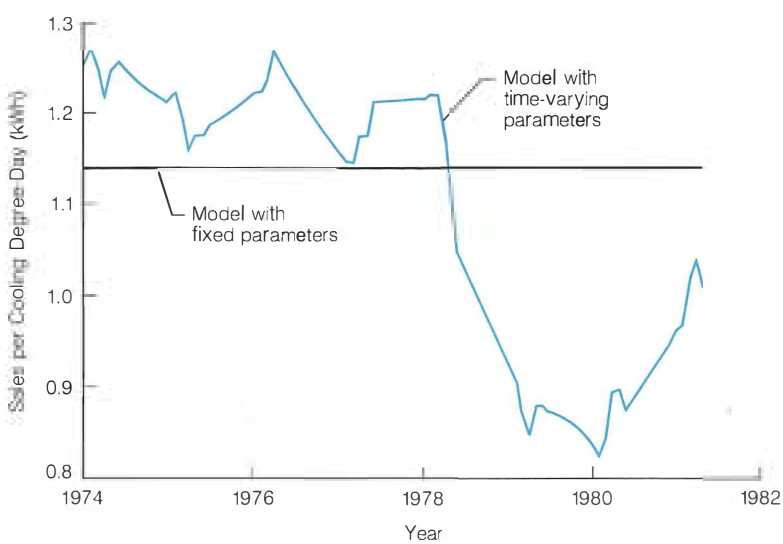


Figure 1 Electricity sales per residential customer per cooling degree-day (base 65°F; 18°C) were estimated for a utility service area by using two types of models: one with fixed values for selected weather and nonweather parameters and one with time-varying values for the weather parameters. In this case the model with time-varying parameters more realistically represents the sensitivity of sales to weather.

COMPENSATION IN FISH POPULATIONS

The effect of power plant cooling systems on fish populations has been a major controversy in plant siting and operation. In particular, experts have disagreed on the ability of fish populations to compensate for power plant–induced mortalities. Understanding the compensatory capacity of fish populations is essential for predicting their response to power plant impacts. Because such predictions are important to maintaining environmental integrity and efficient energy generation, EPRI has initiated a study to develop methods for determining the mortality levels a fish population can experience without adverse effect—that is, for assessing the compensatory capacity of a specific fish population.

Experts generally agree that at least some of the fish entrained through power plants or impinged on plant intake screens are killed, but they disagree substantially about the effects of these mortalities on overall fish populations. Current theory holds that fish populations tend to increase in size until limited by environmental factors that affect reproductive or mortality rates—for example, food or suitable habitat. However, some analysts assume that power plant–induced mortality will reduce populations below the levels at which natural, self-regulatory mechanisms function. If so, fish losses due to power plant operation will result in reduced fish populations. Conversely, other analysts have assumed that power plant–induced mortality is a small fraction of naturally occurring mortality and that natural forces still limit the size of the fish populations. If this theory is true, power plant–induced fish losses will not lead to reduced populations. In other words, increased mortalities resulting from power plants are compensated by reduced natural mortalities.

Both positions may be correct, depending on the situation. In some circumstances, particularly when populations are already depressed, additional mortalities from entrainment or impingement may further reduce population size. However, under most circumstances involving healthy, self-sustaining populations, natural self-regulatory or density-dependent control mechanisms should be adequate to offset power plant–related mortalities and to maintain population size and structure.

Unfortunately for both sides of the issue, we lack the quantitative understanding of population dynamics necessary to separate the different circumstances that relate a population's size or structure to its compensatory capacity. Because resolution of the conflict between these two hypotheses is critical for decisions about power plant siting, design, and operation, EPRI has initiated a research program to determine how to estimate the compensatory capacity of fish populations (RP1633).

Program background

Compensation has long been a subject of fisheries research. EPRI has been active in studying the role of power plants in this process. At the 1975 research issues workshop (EPRI SR-38), the relation between changes at the individual level and responses of populations, communities, and ecosystems was identified as a top research priority. By 1979 progress in population studies, including results from eight EPRI-sponsored projects, led to the recognition of compensation as a critical issue that required intensive study (EPRI WS-78-151).

In response to this need, in February 1982 EPRI held a workshop on compensatory mechanisms in fish populations (EA-2762). International ecologists, industry scientists, and regulators assembled to examine the state of knowledge about compensatory mechanisms, the role of such mechanisms in population regulation, and their relevance to the evaluation of power plant impacts.

The workshop participants concluded that enough knowledge of compensation in fish populations was available to develop a general research plan, although it was not yet possible to specify the details of such a plan. They agreed that the research program should include laboratory, field, and modeling studies, and that its final products should provide meaningful guidelines and information for utilities. The following general research plan was developed: phase 1, conceptual model and specific research plan development; phase 2, specific research studies; phase 3, synthesis of results; phase 4, methodology demonstration; and phase 5, technology transfer.

The group agreed, however, that research priorities and utility industry costs and benefits could not be accurately evaluated until after the development of a specific plan detailing a conceptual framework (for both empirical and modeling research), hypotheses to be tested, and projects to be conducted. The major stumbling block in developing such a plan was the lack of a critical evaluation and summary of existing literature dealing (directly or indirectly) with the quantification of compensatory mechanisms. The workshop participants therefore recommended that the first phase—plan development—proceed on the basis of comprehensive literature reviews and that the resulting draft research plan be evaluated by industry, government, and academic scientists before being implemented.

Phase 1

Phase 1 began in the fall of 1983. The goal of this effort is to develop a research program for defining and quantifying compensatory mechanisms that act to offset varying rates of mortality in fish populations. The program will emphasize mortalities associated with the operation of steam electric power plants. Phase 1 has these general objectives.

- To evaluate existing data on fish population response mechanisms in relation to power plant cooling system impacts, which are defined in terms of chronic exploitation (task 1) and catastrophic intervention (task 2)
- To identify and review models on power plant impacts and population/community regulation that are relevant to plant siting and operational problems and thus merit further study in the effort to develop quantitative understanding (task 3)
- To develop qualitative conceptual models that relate power plant impacts on fish stocks, populations, and/or communities to natural mechanisms for population/community regulation; to identify unknowns and data needs; and to draft a research plan (task 4)
- To organize a technical and industry review of the research plan, with emphasis on assessing the capacity to conduct the required studies and the usefulness of the results for solving industry problems (task 5)

A different contractor is conducting each task: task 1, the University of Rhode Island; task 2, the University of Michigan; task 3, Systech Engineering, Inc.; task 4, R. G. Otto & Associates; and task 5, Science Applications, Inc. For tasks 1–3 (the reviews of existing data and models), there are individual task advisory panels, each consisting of a utility industry scientist and a senior fisheries biologist from government or the academic community. These three advisory panels, along with the principal investigators for tasks 1–3 and a second group of industry scientists and managers (the project advisory panel) selected by the technical manager, will in turn oversee the progress of task 4.

The project is organized to provide two periods of independent work by task groups 1–3, with combined working meetings at the beginning and end of these periods. The first meeting was held in January 1984; its goal was to define a framework for developing a conceptual model (or models) of compensation, as well as to provide feedback on the proposed structure of the literature reviews. Project staff members and the task and project advisory panels attended.

The meeting began with the presentation of position papers on these topics: industry perception of the problem, theoretical and practical aspects of compensation, functional classification of fish, genetic aspects of density-dependent population response, and mechanisms of individual fish response to environmental change. Each of the three task groups then presented a plan for organizing and conducting its literature review. The participants discussed each presentation to sharpen the focus of the task plans. Each group was then to proceed independently with its plan (or modified plan) for six months before the second review meeting, to be followed by a second six-month work period. The literature reviews will be completed in early 1985.

R. G. Otto & Associates is the technical manager of the project; its initial function is to assist the three task groups while protecting their independence. As the three literature reviews near completion, the technical manager will synthesize and integrate the findings for the preparation of the draft research plan and the summary technical report; the principal investigators and advisory panels for tasks 1–3 will then assume a review and guidance role. At the conclusion of the project, the investigators and advisers will present the results—the conceptual model(s), the research plan, and the three technical reviews—to the utility, regulatory, and academic communities for evaluation. *Project Manager: J. S. Mattice*

R&D Status Report
ENERGY MANAGEMENT AND UTILIZATION DIVISION

Fritz Kalhammer, Vice President

ECONOMIC AND FUEL BENEFITS OF COMPRESSED-AIR ENERGY STORAGE

For many years power system planners and operators have appreciated the benefits of energy storage systems that enable electric utilities to optimally match their generation and load. Among the principal advantages of such systems is that they can be charged with relatively inexpensive energy during off-peak periods; this stored energy can then be used as a substitute for more expensive energy from conventional intermediate- and peaking-power sources, thus lowering overall system production costs. In addition, energy storage technologies can help improve the capacity factors of large baseload plants, which are difficult to cycle. As a source of generation that operators can bring on-line quickly in the event of an emergency, storage also enhances utility system reliability. However, the strategy for evaluating energy storage technologies is not simple, and many planning approaches give misleading information. EPRI is working with utilities to overcome this problem.

In the past the only practical energy storage technology available to electric utilities has been pumped-hydro storage. Unfortunately, pumped hydro requires relatively large plants to be economical, and topographic and environmental restrictions limit its applicability. EPRI's Energy Storage and Hydroelectric Generation Program has participated in efforts to develop alternative energy storage technologies for utility systems. Several studies and investigations cofunded with host utilities and DOE (EM-1589, EM-2210, and EM-2351) have identified compressed-air energy storage (CAES) as an alternative to pumped hydro that could be deployed today. EPRI's current focus is on expediting the commercial use of CAES.

CAES assessment

CAES is a commercially mature technology: no major problems in technology exist to prevent the construction of a full-size (220-MW) or minisize (25–50-MW) plant in the United States. EPRI's role has been to support research that will further improve CAES performance and reliability and to coordinate engineering design and system analysis studies for several electric utilities that have expressed interest in building CAES plants.

EPRI, DOE, and individual utilities have sponsored detailed preliminary engineering design studies of CAES since 1977 (RP1081-1, -2, and -3). Projects initiated with Potomac Electric Power Co., Middle South Services, Inc., and Public Service Co. of Indiana have investigated the use of hard rock caverns, salt domes, and aquifer reservoirs, respectively, for containing the compressed air. System analysis efforts have included the development of computer software to determine the most economic CAES dispatch strategy. Table 1 shows projected savings in money and fuel for several utilities, were they to install CAES plants.

CAES not only can provide low-cost intermediate and peaking capacity through the efficient use of coal-fired and nuclear baseload units but also can offer considerable operational flexibility for power system dispatchers. The conventional pumped-hydro power plant is already offering such benefits: its fast rate of response to load demand and its ability to withstand cyclic load duties are allowing many utilities to perform load following and providing them with frequency regulation and spinning reserve. The benefits of these services are, in many cases, greater than those of simply providing energy. Although CAES is similar to conventional pumped hydro in many respects, it interacts with the power system differently. Thus, to provide utilities with a realistic assessment of the functions that CAES can perform and to quantify, where possible, the associated economic benefits, EPRI is cosponsoring with host utilities a series of system planning and operations studies.

CAES for small utilities

Although the majority of the system planning and operational studies sponsored by EPRI have focused on large utility systems, EPRI has recognized that CAES may also find application on rural and municipal utility systems. Thus, EPRI engaged Burns & McDonnell as contractors to perform analyses assessing the

Table 1
PROJECTED SAVINGS WITH CAES INSTALLATION

Utility	CAES Capacity	Money Saved Over 30 Years: 1982 \$ (10^9)	Money Saved Over 30 Years: \$/kW	Oil Saved Annually: Barrels (10^6)	Oil Saved Annually: Barrels per Unit
Potomac Electric Power Co.	Three 225-MW plants	1.6	2400	1.1	360,000
Public Service Co. of Indiana	Four 280-MW plants	3.9	3500	2.1	525,000
Soyland Power Corp.	One 220-MW plant	0.57	2600	0.3	300,000

potential for energy storage applications in small utilities. These studies consisted of a series of generic economic analyses comparing various energy storage technologies to conventional means of providing intermediate and peaking power for municipal and rural utility systems. The energy storage devices considered in these analyses were advanced batteries, pumped hydro, and CAES. Burns & McDonnell compared the cost of supplying intermediate and peaking power from these devices with the cost of supplying the same power through wholesale power purchases or combustion turbines. The results show a significant potential for the application of energy storage technologies by rural and municipal utilities.

However, to draw conclusions about the general applicability of energy storage technologies to small utilities on the basis of generic studies alone proved difficult because cost-benefit analyses of energy storage systems are highly site- and system-specific. The initial generic studies, for example, did not take into account such factors as the actual daily and weekly load shapes of the utilities or the availability of suitable geologic formations for CAES. Thus more detailed, site-specific studies were necessary to gain a better understanding of the problems and potentials associated with CAES applications on small systems.

Three utilities agreed to participate in further studies: Alabama Electric Cooperative, Lincoln Electric System of Lincoln, Nebraska, and Oglethorpe Power Corp. in Georgia. The studies assessed the potential economic feasibility of energy storage for each participant by comparing long-range capacity expansion plans that incorporated CAES and advanced battery storage with each participant's current conventional capacity expansion plan. This involved a number of tasks: data collection, review of the power supply situation and options, reconnaissance siting, development of alternative capacity expansion plans, economic analysis, and sensitivity analysis. Although not part of the EPRI research effort, Soyland Power Corp. performed a similar study with its own funding, and the results of the research were supplied to EPRI.

On the basis of these studies, two utilities took a serious interest in adding CAES to their systems. Although one utility later terminated its plans for installing CAES or any other generation equipment, the other utility is continuing its evaluations.

CAES planning approach

The PROMOD III System, developed by Energy Management Associates (EMA), is a comprehensive tool for performing major production cost analyses. Economic studies of potential CAES units for Houston Lighting & Power Co. and The Cleveland Electric Illuminating Co. have used this tool.

PROMOD III incorporates a large number of features to facilitate the accurate modeling of an electric utility system's operation. The model uses a probabilistic simulation method to evaluate system reliability and production costs and employs three separate load duration curves to model weekday, weeknight, and weekend load hours independently. Detailed generating unit characteristics can be employed to give an accurate representation of partial outages, maintenance durations, and full outages, whether forced or planned. In addition to nuclear and fossil fuel units, PROMOD III can model storage and run-of-river hydro plants, pumped-hydro storage units, and CAES units by using a specific logic that reflects the special nature of each technology. For CAES the basic assumptions of the logic are as follows.

- CAES is used when needed for reliability improvements, regardless of economics.
- The CAES reservoir is charged only during weeknights and weekends. (PROMOD III represents each month by a typical week, which the user subdivides into weekday, weeknight, and weekend periods.)
- The CAES unit generates power only on weekdays, except when needed to improve reliability. (Charging and generation from the CAES unit are balanced on a weekly basis.)
- Charging and generation from the CAES unit are performed whenever possible at maximum capacity; the methodology utilizes user-supplied differences in efficiencies if charging and generation are performed at part-load capacity levels.
- For every kWh generated, the CAES plant requires about 0.74 kWh of electric energy for the compression cycle and about 4000 Btu of oil or gas energy for the turbine expansion-generation cycle.

Modeling the dispatch of the CAES unit with PROMOD III begins with the development of cost tables. The amount and cost of a unit's potential charging energy, derived from its weeknight and weekend load duration curves, are stored in tables for both time periods. Then the amount and cost of potential generating energy that the CAES unit can off-load or replace, similarly derived from the weekday load duration curve, are entered into a weekday table. After the cost tables are developed, PROMOD III first uses the CAES unit to improve reliability by reducing unserved energy throughout the week. The CAES unit is assumed to use the cheapest available charging energy in the weeknights and weekends for this purpose, although reliability is improved regardless of economics. The economic dispatch of the CAES unit then proceeds, and the generating costs and savings of the CAES unit are determined from the cost tables.

Because EMA developed the PROMOD III subroutines with EPRI funding, they are available to member utilities without license or royalty fees. These PROMOD III studies have led both Houston Lighting & Power and Cleveland Electric Illuminating to actively consider CAES in their expansion plans.

General results

Several general conclusions can be drawn from the many applications of PROMOD III and related studies. These studies have shown that the interpretation of results from computer models used for storage analysis is more subtle and complex than that from models used for nonstorage analysis. Because the amounts of compression and generation dispatched are interrelated, the results of an analysis sometimes seem counterintuitive.

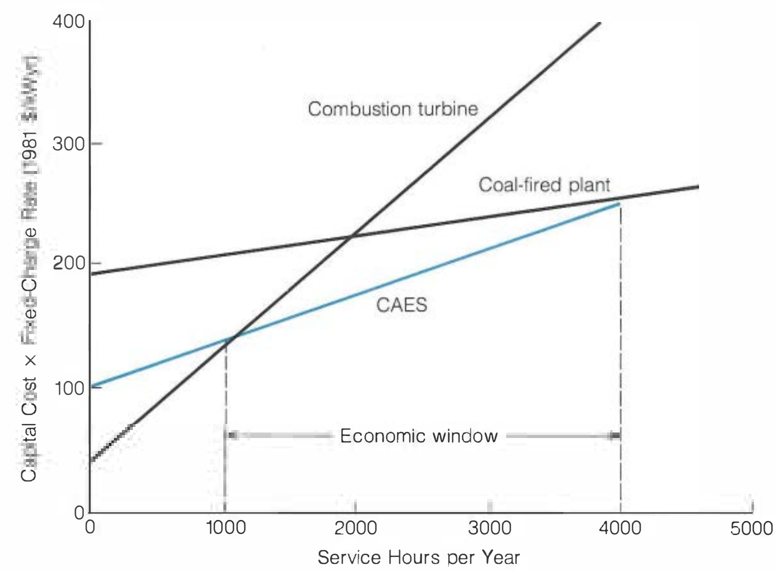
The studies have also shown that cost-benefit results strongly depend on the assumed size (MW and storage hours) of the CAES plant, as well as on the assumed differential between coal and oil or gas prices for the future. Generally, an undersized CAES plant will show a better cost-benefit ratio than an oversized plant. Figure 1 illustrates the best economic window for CAES use.

Utilities should not consider CAES solely as a substitute for peak load nor solely as a substitute for a coal-intermediate plant but rather as an intermediate-duty plant that can delay the purchase of a new unit, as well as satisfy current peaking and spinning reserve duty. CAES is also an excellent regulation duty plant because its heat rate degrades by only 7% at 20% part-load.

Computer predictions are at best a simplistic technique to match the realities of load growth, inflation, fuel prices, and so on; they should be used only as a guide in development plans for future additions. For example, predictions do not include many intangible benefits, such as the security provided by spinning reserve.

To assist planners in analyzing CAES, utility-cofunded studies will continue. The objectives of these efforts will be in part to improve tools for CAES analysis and to provide further insight into utility system aspects of CAES technology. *Project Manager: Robert B. Schainker*

Figure 1 Economic data illustrate the window of opportunity for effective use of CAES technology. In this case, the best use of the CAES plant is between 1000 and 4000 h/yr.



ELECTRIC VEHICLES IN THE COMMERCIAL SECTOR

Although electric-powered vehicles date to the earliest part of the automobile age, they have never gained prominence as a means of over-the-road transportation. Emerging technology has enhanced their potential for this use, but a lack of data regarding both desirable vehicle configurations and potential market size has hindered successful commercialization. The objective of RP1569-3 has been to redress these data inadequacies with respect to commercial fleet vehicles by gathering information from fleet managers about vehicle travel requirements, cost and range trade-offs, and operational practices. The study, performed by the Institute for Social Research of the University of Michigan, was commissioned by EPRI and Detroit Edison Co. It is part of an ongoing research agenda that has as its long-term goal the successful commercial development of over-the-road electric vehicles (EVs).

A review of the EV literature in 1982 exposed a serious lack of the kind of information needed to justify large-scale commitments to further EV market development or demonstration activities. Earlier research and demonstration results had led to mixed conclusions about EV market potential. More important, they lacked the methodological rigor and detail necessary for planning and investment decisions. This was especially the case regarding commercial-sector applications, which may hold the most promise for quantity EV adoption over the next decade.

Further complicating the decision environment was the cutback in EV development efforts by the federal government and certain automobile manufacturers. Thus, despite the obvious benefits to the electric power industry associated with quantity EV production, by mid 1982 it was clear that the prospects for near-term EV commercialization might dim further unless new studies could indicate significant market potential and produce a realistic market development strategy.

The successful commercialization of EVs will require a commitment from major manufacturers and other infrastructure participants and a commitment from prospective buyers. A market development strategy must provide timely, reliable, and appropriate information to both potential suppliers and potential buyers so that they can base their commitments (which are made at different points in the commercialization process) on informed self-interest. Practically speaking, the data must convince suppliers that the potential market is large enough to be profitable and convince prospective buyers that a dependable, economically attractive vehicle and an infrastructure exist (or will exist).

In light of these circumstances, the overriding goal of this study has been to provide information useful in guiding programs for the technology development, market assessment, and demonstration of EVs. Each of these three elements is crucial to successful EV commercialization; taken together, they provide an integrated framework for market development.

The first step in this effort was a pilot study conducted in early 1983. This study had two components: a pilot survey of commercial fleet operators in the Detroit Edison service area and an analysis of ongoing EV field-test and demonstration projects. The survey provided both an initial estimate of potential EV market size and a methodology that future studies can use in evaluating the size and characteristics of the national market and submarkets. The analysis provided information needed to begin a new round of commercial-sector demonstrations that would avoid past mistakes and maximize opportunities for success.

A full-scale study followed the pilot study. A nationwide sample of establishments with vehicle fleets was constructed from a comprehensive list drawn up by Dun & Bradstreet, Inc., and fleet managers were contacted by telephone. A total of 583 interviews were conducted in the fall of 1983, with an overall response rate of 92%. By using scientific sampling procedures, the researchers have translated the sample data into estimates for the entire country with known degrees of precision. Because any systematic bias in the data would be attributable to undercoverage in the list used for sampling, estimates of market potential can be considered conservative.

Commercial fleet vehicle characteristics

There are estimated to be approximately 6 million cars and 7 million light-duty trucks and vans in commercial fleets in the United States. Table 2 presents information on fleet vehicles that fall into three daily mileage categories: less than 30 mi (48 km), 30–59 mi (48–95 km), and 60–89 mi (97–143 km). As indicated there, almost 20% of all commercial vehicles typically travel less than 30 mi/d and almost 50% travel less than 60 mi/d. In general, light-duty trucks and vans tend to have lower daily mileage requirements than fleet cars. For this reason and others discussed below, trucks, and especially vans, appear to be the most promising body styles for initial quantity EV production.

Vehicles with low daily mileage requirements tend to be concentrated in relatively small fleets. Almost two-thirds of all vehicles

Table 2
MILEAGE ATTRIBUTES OF LIGHT-DUTY COMMERCIAL VEHICLES

	Typical <30	Daily 30–59	Mileage 60–89
Estimated number of vehicles (millions)	2.5	3.3	2.3
Percentage of all vehicles in commercial fleets*	20	26	18
Average daily mileage	17	44	72
Vehicles occasionally driven >30 mi/d (%)	56	–	·
Vehicles occasionally driven >60 mi/d (%)	38	59	·
Vehicles occasionally driven >90 mi/d (%)	–	41	60
Average daily mileage at >40 mi/h	–	4.5	9.3

*For the first two categories the range of uncertainty is ±4%; for the third category it is ±3%.

typically traveling less than 60 mi/d are in fleets of six or fewer vehicles.

EVs have traditionally been good candidates for applications involving fixed routes. In this regard, trucks and vans are again more promising than cars: 20% of trucks and vans, as opposed to 4% of cars, travel on fixed routes of less than 60 mi/d. Most vehicles, however, do not operate on fixed routes. Thus it is important to recognize that although 46% of all commercial vehicles typically travel less than 60 mi/d, only 21% always remain within this range. A full 25% must occasionally travel longer distances. This need for longer trips could make the use of a limited-range EV impractical for many fleets. Nevertheless, over one-third of the fleet managers indicated that they could reassign the infrequent longer trips to other vehicles with relative ease. In that case, as many as 30% of all commercial vehicles could have travel patterns that never exceed 60 mi/d. This would amount to over 3.5 million vehicles.

EVs are also considered to have a special efficiency advantage in applications requiring frequent stops and starts. Once again, trucks and vans fall into this usage pattern far more frequently than commercial cars. Over 10% of trucks typically driven less than 30 mi/d are stopped and restarted more than 20 times a day; for trucks driven less than 60 mi/d, the figure is over 25%. Furthermore, just under 10% of the trucks in both mileage categories are stopped and left running more than 100 times a day.

The constraints of conventional battery technology place EVs at a disadvantage in applications requiring long-distance travel at high speed. In this regard, however, the data are encouraging for EV adoption. Fleet cars typically driven 30–59 mi/d average only 5.8 mi (9.3 km) at speeds greater than 40 mi/h (64 km/h); trucks in the same mileage category average only 3.4 mi (5.4 km) at high speed. Although high-speed driving can decrease the range capability of EVs, the vast majority of commercial vehicles are parked for a sufficient period during the day to permit recharging. Trucks are far more likely than cars to be available for conventional overnight recharging on company premises.

Additional constraints on EVs, particularly the earlier models, have been their rather small body shells and limited payload capacity. The commercial fleet data indicate that the payload constraint is not necessarily a major barrier to EV substitution. In terms of weight, about 70% of all trucks and vans typically carry loads less than 500 lb (230 kg). In terms of cargo volume, over 60% of truck payloads are not considered especially bulky for their weight.

Effect of range on market potential

To evaluate how future decisions on EV range may constrain the size of the potential EV market, researchers developed four substitution categories that correspond to different levels of potential EV performance. All existing fleet vehicles whose trip requirements fall within a given category are considered to offer high substitution potential for the EV whose performance corresponds to that category. The four categories are as follows.

- Vehicles typically traveling less than 30 mi/d
- Vehicles typically traveling less than 30 mi/d, plus vehicles traveling 30–60 mi/d that are parked for at least two hours a day and are driven less than 8 mi/d (13 km/d) at speeds above 40 mi/h
- Vehicles typically traveling less than 60 mi/d
- Vehicles typically traveling less than 60 mi/d, plus vehicles traveling 60–90 mi/d that are parked for at least two hours a day and are driven less than 8 mi/d at speeds above 40 mi/h

Depending on which of the four performance categories is used, EVs could replace between 25% and 75% of all vehicles in today's average commercial fleet (Figure 2); this translates to between 2.5 and 7 million commercial vehicles. If only small vehicles are considered, the number is between 0.4 and 1.5 million vehicles.

As noted earlier, light-duty trucks and vans appear to be the most promising initial market for EV substitution. Overall, trucks and vans represent approximately 80% of all vehicles with a high substitution potential as defined by the four categories. The largest numbers of vehicles with high substitution potential are in moderate-size fleets (2–19 vehicles).

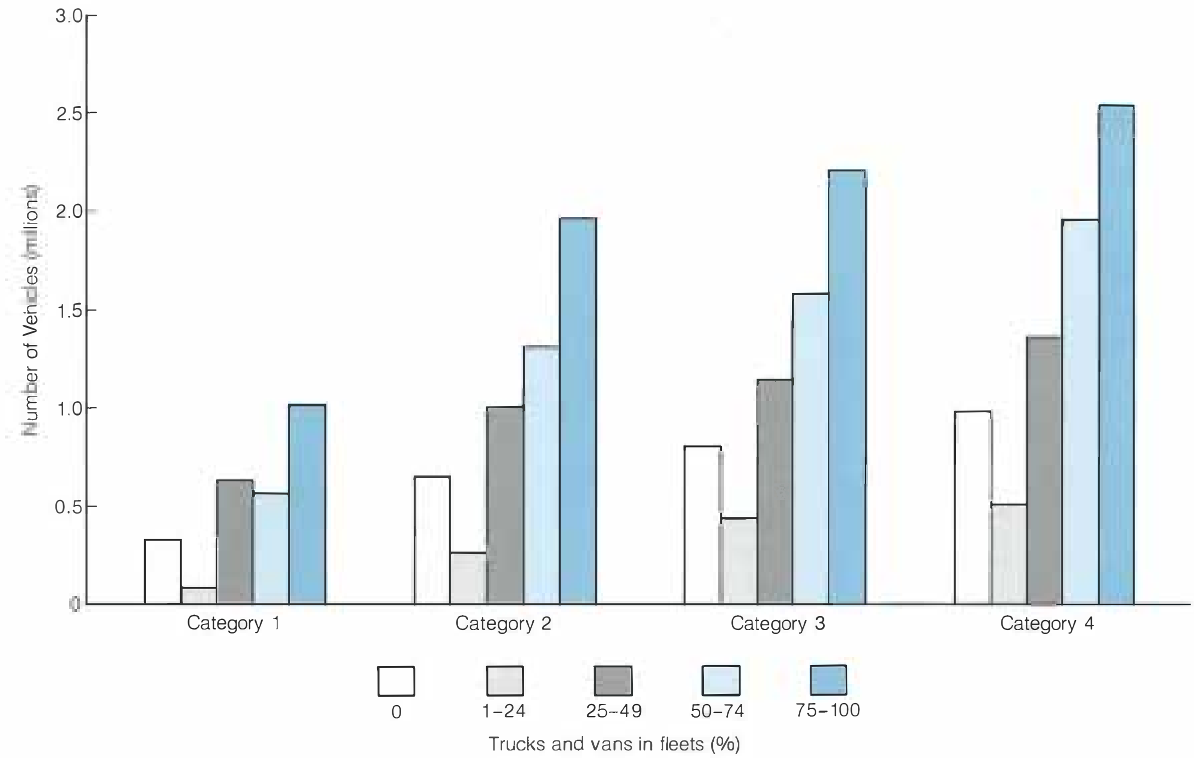
From a marketing standpoint, range is not a major factor influencing which industries will find EVs the most (or least) appealing. Overall, the wholesale/retail trade, construction, and service sectors appear to have the most promise for EV substitution. On the other hand, range may significantly affect the potential of EVs in terms of geographic region. Relatively short-range EVs will have their largest potential market in the northern industrial region. Vehicles with a somewhat longer range could open up a large market in the South.

Future research needs

There are a number of areas in which additional market-oriented research could further the potential for successful EV development. The near-term research agenda should give high priority to two of these areas.

First, there is a need for the collection and analysis of more data pertaining to the optimal trade-off between such factors as vehicle cost, payload, size, speed, acceleration, and range. These are crucial strategic decisions with respect to EV technology development and market potential. Second, further analysis of EV infrastructure requirements is needed. This effort should parallel appropriate planning activities to lead to the initiation of a realistic infrastructure development process. The goal of this process should be the capability of supporting large-scale EV demonstrations in the commercial sector during 1987–1988. *Project Manager: Gerald Mader*

Figure 2 Maximum EV substitution potential was determined for four vehicle performance categories: category 1, vehicles traveling less than 30 mi/d; category 2, vehicles traveling less than 30 mi/d plus some vehicles traveling 30–60 mi/d (those parked at least two hours a day and traveling less than 8 mi/d at high speed); category 3, vehicles traveling less than 60 mi/d; category 4, vehicles traveling less than 60 mi/d plus some vehicles traveling 60–90 mi/d (those meeting the parking and speed requirements defined in category 2). As the graph shows, the number of vehicles falling within each category increases substantially with the percentage of trucks and vans in the fleets.



R&D Status Report
NUCLEAR POWER DIVISION

John J. Taylor, Vice President

ON-LINE LEAK SEALING

Process media leaks (e.g., steam and water) from such system components as valves, flanges, and pipes often result in plant shutdown for repair, particularly in nuclear power plants, which have stringent limits on allowable leaks. Temporary on-line leak sealing, performed while the system remains in operation, may provide plant operators with an alternative to an unscheduled plant shutdown. Such temporary repairs may be cost-effective by delaying the plant shutdown and by preventing or minimizing component damage (e.g., from steam cutting) that might have occurred if the leak had been allowed to persist.

Several U.S. companies offer commercial on-line leak-sealing products and services to the utility industry, usually by providing the technicians who seal the leaks with the company's products, equipment, and techniques. EPRI has conducted research to (1) evaluate the effectiveness of the commercial leak repair services, with particular emphasis on their application in nuclear power plants, (2) determine limitations of on-line leak repair, and (3) provide recommendations for potential users of such services (RP1328-1). Combustion Engineering, Inc., carried out the project, which is reported in NP-3111.

Three companies—Federal Industrial Services, Inc.; Furmanite America, Inc.; and Leak Repairs, Inc.—demonstrated their equipment and techniques for a variety of leaks. Pipeline Development Co. participated in a limited part of the project. The leak repair equipment and techniques used were those commercially available during the evaluation period (August 1980 to January 1982).

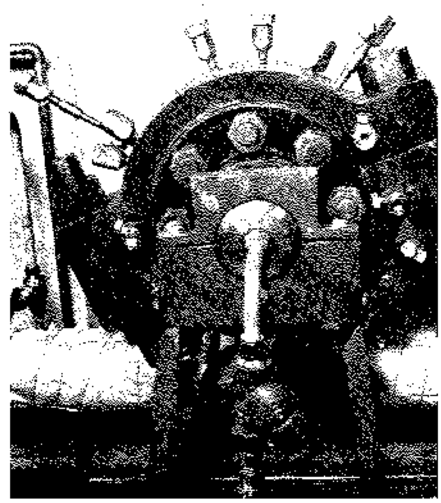
Each company demonstrated its sealing techniques under several on-line leak conditions. One leak configuration involved a small hole in piping; the following combinations of hole size (diameter) and fluid temperature were investigated: 1⁄64 in (0.4 mm), 540°F (282°C); 1⁄32 in (0.8 mm), 200°F (93°C); 1⁄16 in (1.6 mm), 600°F (316°C) and 200°F. Other tests involved a scratch across mating flange faces for these flange sizes and fluid temperatures: 3⁄4 in (19 mm), 200 and 600°F; 4 in (102 mm), 600°F. Various leaks in valve stem packing, including asbestos packing and graphite packing, were investigated for fluid temperatures of 200 and 600°F. Borated water at 2200 psig (15.4 MPa) was the leaking fluid in all tests.

Flange or pipe leaks are generally repaired by means of a heavy enclosure clamped to the leaking component. Figure 1 shows a typical flange enclosure. In some cases, the leakage path is mechanically peened to reduce the magnitude of flow before enclosure installation. Sealant is pumped directly into these enclosures to stop the leak. One vendor's enclosure required that the leaking flange be drilled and tapped to accept the sealant injection ports. Valve stem packing leaks were repaired without the use of enclosures in all cases. Stuffing boxes were drilled and tapped and the sealant pumped directly into the leaking packing.

Repairs on about 50% of the specimens were successful after a 48-hour exposure to the borated water at full pressure and temperature. Selected specimens were also subjected to long term thermal cycling tests, and leakage measured after 2, 8, and 14 weeks. Most specimens that did not leak after the 48-hour exposure survived the temperature and pressure cycling. A few samples deteriorated to gross leakage.

The extrusion of injected sealant into the process stream may contaminate the process fluid or block normal flow, making the use of on-line leak sealing methods risky. None of the sealing techniques preclude this extrusion. Three of the four vendors, however, offer mechanical sealing fixtures (Figure 2) with chambers for housing the leaking component. The mechanical seal fixture has a perimeter seal into which the sealant is pumped. Thus because the sealant does not normally enter the leak path, the risk of sealant extrusion into the process stream is reduced significantly.

Figure 1 Flange enclosure for on-line leak sealing. Sealant is pumped through the injection nozzles directly into the leak path.



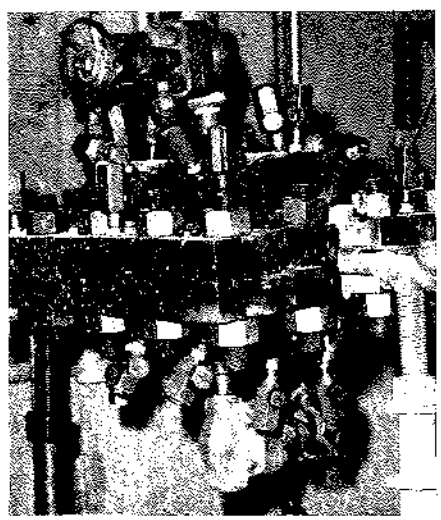


Figure 2 Mechanical sealing fixture for on-line leak sealing. Sealant is pumped through the injection nozzles into a fixture's seal and does not directly contact the leak path.

Sealant material impurity also represents a risk in this sealing method. Chlorine and sulfur are particularly harmful because of their effects on the metallurgy of pressure boundary components. Each vendor's sealant material was analyzed after thermal curing, gamma radiation in primary coolant (borated water) at ambient and at operating temperature, and thermal aging. Results varied, but total chlorine was, in all cases, higher than an established acceptance criterion for nonmetallic materials in or on nuclear steam supply system components. In one analysis, sulfur was also found to be relatively high.

In the performance of this project, each contractor is assumed to have provided its most experienced technicians, best available fixtures, and nuclear-grade sealants. Results obtained, therefore, should be representative of field performance. The test data and observations during the project show that the products and services of all participants are approximately equivalent. Despite their variation, all sealing methods showed failures as well as perfect repairs, and each vendor had at least one incident of sealant extrusion into the process stream.

The project's objective was not to determine which, if any, vendor provided the most effective and consistent leak repairs. Rather, repairs and subsequent long-term tests offered substantial insight into the state of the art of on-line leak repair and resulted in the following conclusions and recommendations.

Conclusions

Sealant behavior during injection is unpredictable and difficult to quantify. Off-gassing with subsequent spontaneous expulsion and extrusion of sealant occurred several times during the tests. The sealants' curing requirements varied, but vendors demonstrated reasonable knowledge of their sealants' performance and capabilities. Sealant extrusion into the process stream was infrequent, but observations made during the test program suggest that such extrusions cannot be completely prevented. Mechanical sealing fixtures (Figure 2) may significantly reduce the risk of such extrusion.

Diminishing the leakage flow by mechanical means, such as peening or wrapping with wire or clamps, does not appear to affect the ultimate effectiveness of the repair, although this action may inhibit sealant extrusion into the stream and simplify the sealing process.

Limiting sealant injection pressures to system (line) pressure appears to be an effective technique for inhibiting sealant extrusion. Viscous and semisolid sealants require hydraulic injection pressures significantly in excess of system pressure, which provides little control sensitivity for preventing extrusion. Further, injection pressures for these sealants must be determined indirectly from the injection tools and not from the sealant injection line itself. Less-viscous (fluid) sealants may be injected at or near system pressure, which allows direct pressure monitoring.

Frequent sealant expulsion during the repair process suggests that knowledge of total sealant volume injected (predetermined volume control) is a useful guideline but does not guarantee prevention of sealant extrusion.

All sealants and repairs deteriorated under thermal cycling conditions. It may be inferred with reasonable certainty that successful repairs that failed with repeated thermal cycles would have remained effective under steady-state conditions.

Valve leak repairs were generally less successful than pipe and pipe flange leak repairs. This phenomenon may be attributed to the fact that most of the valves were repaired without the use of enclosures but, rather, by injecting sealant or pumpable packing material directly into the leaking component. The effectiveness of these repairs is thus more closely related to the performance of the sealant (or pumpable packing material) itself.

Recommendations

To determine the presence of reactive elements potentially harmful to the system being sealed, utilities employing leak repair vendors should require certified, independent chemical analyses of each batch of the sealants.

A repair with significant leakage within 48 hours of repair completion should be considered a failure and a new repair initiated.

The added mass of repair fixtures may compromise the seismic qualification of piping systems employing such repairs (nuclear plants). Seismic requirements should be considered before repairs are initiated. Utilities should consider the design basis for the fixtures because these relatively massive structures become a new pressure boundary once the repair is made. Further, when an enclosure is used in the sealing of a flange leak, the sealant is injected at high pressure between the flange faces and may put significant additional stress on the flange studs. Diminishing the leakage flow of flange leaks by peening flange faces should be limited to minimize the complexity of subsequent permanent repair.

All leaks repaired with injected sealant should be considered temporary, and permanent repairs should be made as soon as practical. The use of an additive to speed up curing should be evaluated for specific applications.

In view of the relatively low percentage (~50%) of this project's successful on-line leak sealing, utilities that have used on-line leak sealing are requested to contact the project manager, describe their experiences, and suggest R&D needs in this area. *Project Manager: Boyd Brooks*

New Contracts

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
Advanced Power Systems				
RP790-4	Evaluation: Photovoltaic Concentrator Optics	7 months	50.9	Precision Optics Corp. *R. Taylor*
RP1193-7	Investigation: Growth and Properties of Hydrogenated Amorphous Silicon Thin Films for Photovoltaic Applications	18 months	437.0	University of Illinois at Urbana-Champaign *J. Crowley*
RP1590-4	Operational Data From 120-Unit Wind Turbine Cluster	6 months	30.0	Fayette Manufacturing Corp. *F. Goodman, Jr.*
RP2029-13	Phased Construction of Gasification–Combined Cycles	12 months	400.0	Fluor Engineers, Inc. *A. Lewis*
RP2048-7	Materials Development for IGCC Plants: Development of High Chromium Corrosion-Resistant Clad Heat Exchanger Tube	7 months	63.5	Amax Materials Research Center *W. Bakker*
RP2221-5	Evaluation: Phosphate Process for Sulfur Recovery	6 months	100.0	Fluor Engineers, Inc. *B. Louks*
RP2505-2	Lurgi-Ruhrgas Process Test on Utah Coal	7 months	354.4	Bechtel Group, Inc. *L. Atherton*
RP2526-2	Characterization of KILnGAS Waste Waters	3 months	60.0	Oak Ridge National Laboratory *M. Epstein*
RP2562-1	Human Factors Study for Gas Turbine Power Plant Expert Systems	9 months	55.2	Honeywell, Inc. *C. Dohner*
Coal Combustion Systems				
RP1184-8	Survey: Cycling Fossil Fuel Plants	9 months	76.1	Ebasco Services, Inc. *F. Wong*
RP1263-22	Mobility of PCBs, PCDFs, and PCDDs in Soils	7 months	56.1	Battelle, Pacific Northwest Laboratories *R. Komai*
RP1263-23	Field Testing the S-Cubed Gas Chromatograph, PCBA-102	15 months	94.8	Brown and Caldwell Consulting Engineers *R. Komai*
RP1883-5	Coal Pulverizer Materials Development Erosion Studies	23 months	111.1	Central Electricity Generating Board *W. Bakker*
RP1893-2	Monitoring Boiler Erosion by Thin Layer Activation	12 months	199.5	Spire Corp. *J. Scheibel*
RP1895-23	CWS Burner Project Support	9 months	40.0	Bechtel Group, Inc. *R. Manfred*
RP2300-6	Feasibility Study: Condenser Performance Test Facility	5 months	34.3	Heat Exchanger Systems, Inc. *W. Chow*
RP2422-6	Test Program: Flowable Fly Ash	24 months	98.6	Detroit Edison Co. *D. Golden*
RP2534-02	Pilot Evaluation: Limestone Dual-Alkali Process	14 months	373.5	Bechtel Group, Inc. *T. Morasky*
RP2605-1	Cement-Concrete Use, Products Coordination	12 months	100.0	Michael Baker, Jr., Inc. *R. Komai*
Electrical Systems				
RP1263-18	Arc Furnace Technology for PCB Capacitor or Other Materials Destruction	16 months	2885.0	Arc Technologies Co. *R. Tackaberry*
RP2205-2	Dry-Type Capacitor—Partial Discharge Suppression	12 months	237.6	General Electric Co. *H. Songster*
RP2550-1	Scoping Study: Integrated Power Systems Analysis Package	13 months	206.4	Carlsen & Fink Associates, Inc. *J. Lamont*
RP7898-3	Dynamic Rating and Underground Monitoring System	5 months	38.2	Underground Systems, Inc. *S. Kozak*
Energy Analysis and Environment				
RP1225-3	Evaluation of Oral-Nasal Ventilation	12 months	140.3	University of California at Santa Barbara *C. Young*
RP2359-23	Probabilistic Fuel Burn Forecasting	7 months	74.9	Applied Decision Analysis, Inc. *H. Mueller*
Energy Management and Utilization				
RP2035-9	Development of Equipment for Residential Load Management Experiments	21 months	328.0	Energy Interlock Corp. *G. Gurr*
RP2036-19	Design Guide: Stratified Chilled-Water Storage	5 months	36.2	Reid Crowther & Partners, Ltd. *C. Hiller*
RP2570-1	Center for Metals Production	45 months	1900.0	Carnegie-Mellon University *L. Harry*

New Technical Reports

Each issue of the *Journal* includes information on EPRI's recently published reports.

Inquiries on technical content may be directed to the EPRI project manager named at the end of each entry: P.O. Box 10412, Palo Alto, California 94303; (415) 855-2000.

Requests for copies of specific reports should be directed to Research Reports Center, P.O. Box 50490, Palo Alto, California 94303; (415) 965-4081. There is no charge for reports requested by EPRI member utilities, government agencies (federal, state, local), or foreign organizations with which EPRI has an agreement for exchange of information. Others in the United States, Mexico, and Canada pay the listed price. Overseas price is double the listed price. Research Reports Center will send a catalog of all EPRI reports on request.

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ADVANCED POWER SYSTEMS

Underground Coal Gasification Simulation
AP-3496 Final Report (RP452); $11.50
Contractor: University of Wyoming
EPRI Project Manager: J. McDaniel

Proceedings: Third Annual EPRI Contractors' Conference on Coal Gasification
AP-3586 Proceedings (RP1654); $29.50
EPRI Project Managers: N. Holt, G. Quentin

Reliability Improvements in Combined-Cycle Systems Through an Advanced Steam Generation Concept
AP-3598 Final Report (RP1926-3); $10.00
Contractor: Solar Turbines Incorporated
EPRI Project Manager: R. Duncan

Solid-Liquid Separation for Liquefied Coal Industries
AP-3599 Final Report (RP1411-1); $46.00
Contractor: University of Houston
EPRI Project Manager: N. Stewart

Petroleum Coke Outlook
AP-3620 Final Report (RP2221-3); $17.50
Contractor: The Pace Company Consultants & Engineers, Inc.
EPRI Project Manager: S. Alpert

COAL COMBUSTION SYSTEMS

Construction Materials for Wet Scrubbers: Update
CS-3350 Final Report (RP1871-3); Vol. 1, $20.50; Vol. 2, $35.50
Contractor: Battelle, Columbus Laboratories
EPRI Project Manager: C. Dene

Corrosion and Erosion in PFBC Environments
CS-3363 Final Report (RP979-14); $10.00
Contractor: General Electric Co.
EPRI Project Manager: J. Stringer

Effects of Phosphate Environments on Turbine Materials
CS-3541 Final Report (RP1886-1); $14.50
Contractor: General Electric Co.
EPRI Project Manager: B. Syrett

FGD Chemistry and Analytical Methods Handbook
CS-3612 Final Report (RP1031-4); Vol. 1, $19.00; Vol. 2, $73.00; Vol. 3, free of charge
Contractor: Radian Corp.
EPRI Project Manager: D. Stewart

Flue Gas Desulfurization Chemistry Studies: Limestone Grindability
CS-3618 Final Report (RP1031-4); Vol. 1, $17.50; Vol. 2, $23.50
Contractor: Radian Corp.
EPRI Project Manager: D. Stewart

Coal-Cleaning Test Facility: 1984 Test Plan
CS-3621 Interim Report (RP1400); $16.00
Contractors: Raymond Kaiser Engineers, Inc.; Science Applications, Inc.
EPRI Project Managers: C. Harrison, J. Hervol

Proceedings: Western Coal Quality Workshop
CS-3626 Proceedings (RP1338-6); $13.00
Contractor: Norwest Resource Consultants, Inc.
EPRI Project Manager: R. Row

Groundwater Model Parameter Estimation Using a Stochastic-Convective Approach
CS-3629 Topical Report (RP1406-1); $10.00
Contractor: Battelle, Pacific Northwest Laboratories
EPRI Project Manager: D. Golden

ENERGY ANALYSIS AND ENVIRONMENT

Integrated Lake-Watershed Acidification Study: Hydrologic Analysis
EA-3221 Final Report (RP1109-5), Vol. 2; $11.50
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EPRI Project Manager: E. Beardsworth

Toxicity Profiles of PCB Substitutes
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EA-3575 Final Report (RP1955-3); $10.00
Contractor: Associated Power Analysts, Inc.
EPRI Project Manager: J. Chamberlin

Electric Utility Conservation Programs: Assessment of Implementation Experience
EA-3585 Final Report (RP2050-11); Vol. 1, $10.00; Vol. 2, $26.50
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EPRI Project Manager: C. Gellings

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EPRI Project Manager: S. Braithwait

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EPRI Project Manager: I. Murarka

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EA-3622 Final Report (RP1477-1); $17.50
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EPRI Project Managers: L. Williams, C. Gellings

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EPRI Project Manager. A. Karp

NUCLEAR POWER

ATHOS: Computer Program for Thermal-Hydraulic Analysis of Steam Generators—Applications
NP-2698-CCM Computer Code Manual (RP1066-1), Vol. 4; $20.50
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NP-3445 Final Report (RP1935-3); $8.50
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EPRI Project Manager H. Ocken

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ELECTRIC POWER RESEARCH INSTITUTE
Post Office Box 10412, Palo Alto, California 94303

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