Coal That Flows

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Cover: Coal-water slurries are the goal of intense commercial activity to develop a replacement fuel for oil-design utility boilers. These slurries, which have the consistency of latex paint, are made up of fine coal particles (about 70%) suspended in water (about 30%), with small amounts of chemical additives (less than 1%) mixed in to increase stability.

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Coal-Water Slurry: Collecting on Insurance

An important part of EPRI's work for the utility industry is perceived as insurance—a hedge against the uncertainties of an unpredictable future. Much of our research, our insurance premium so to speak, is intended to cope with problems that may arise because of changes in the technologic, economic, or regulatory climate in which electric utilities operate. The most rapid and disruptive changes experienced in recent times have been the result of oil shortages in 1973 and 1979. In response to the first oil embargo in 1973, utilities have been "squeezing" oil out of their system. As a result, oil use by electric utilities has dropped by more than 50%. No new oil plants have been built, and many plants have reverted back to coal after a decade or more of burning oil. Yet if we analyze the data carefully, we can see that the industry's reserve margin is still heavily in the form of underutilized oil plants. Because new plant construction is down, the evidence points to a greater role for oil-burning units in meeting the growing electricity demand currently being recorded as the economy recovers.

Part of the industry's insurance against oil supply disruptions has been EPRI's work on coal-oil mixtures (COM) and coal-water slurries (CWS), initiated in 1974 and 1978, respectively. Both COM, mixtures of 50% coal and 50% No. 6 oil, and CWS, mixtures of 70% coal and 30% water, seemed attractive because they could be fired in boilers that had been designed only for oil. COM fuel was relatively easy to produce, and three large utility tests did take place; however, by the time these experiments had been completed, oil was no longer in short supply and the crisis-induced incentive to convert was gone.

Nevertheless, the utility-scale tests were beneficial in altering strong perceptions within the industry. For example, it became clear that *some* coal could be burned in *some* boilers designed for oil (albeit with some load derating), an idea that had been dismissed out of hand by many in the industry. Still, combustion performance in two of the utility tests was unexpectedly poor when using modified oil burners without benefit of prior R&D or test work. The obvious lesson was that further development work would require a systematic, step-by-step approach to identify and correct problems well ahead of costly field demonstrations.

When EPRI-sponsored economic evaluation studies revealed that the cost differential between COM and fuel oil was too small to justify conversions in most cases, utility emphasis shifted quickly from COM to CWS. The greatest concern in substituting water for oil in the coal mixtures was with maintaining combustion stability and carbon burnup in the relatively small furnace volumes of oil-design units. It was feared that use of CWS would result in even further load downratings than was the case with COM. EPRI's CWS program addressed each of these issues, first in the laboratory and then in converted field boilers. Working closely with manufacturers, researchers conducted combustion tests at increased burning rates, culminating in an industrial boiler demonstration in 1983. In order to minimize boiler derating, the studies were performed with slurry made from cleaned coal with a low ash content—a reasonable choice, since CWS enables physical coal cleaning to be easily incorporated as an integral part of the slurry preparation process.

The next step required is an extended demonstration at utility scale. We believe such a test will show CWS to be economic for some applications, even at today's oil prices. Demonstration is important because to be truly available as "insurance," a number of component systems must first be tested. For example, a prototype of the infrastructure must exist to support large-scale CWS production and the transport of slurry over large distances. Engineers must have wrestled with the problems of retrofitting burners and ash-handling equipment. The models for derating must be tested against reality so there is confidence when the need for large-scale use of CWS (or any other oil alternative) arises.

Confidence based on hard experience is the key, for without it, the next crisis will likely breed a confusing array of unproven "solutions." Within this decade, EPRI's work on CWS is expected to culminate in economic applications in the utility industry, as well as in such other areas as the paper, chemical, refinery, and steel industries. As a result, the insurance premium will have been paid and the policy itself backed by the most important asset, experience.

Shelton Ehrlich

Shelton Ehrlich, Program Manager
Fluidized-Bed Combustion and Alternate Fuels
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Authors and Articles

Grind up some coal, add enough water to get the consistency of oil, and burn it. Simple? Relatively. Ready? Almost. Universal substitute for oil? No. These and other questions are answered in **Oil's New Rival—Coal-Water Slurries for Utility Boilers** (page 6). Written by Taylor Moore, *Journal* feature writer, this month's cover article draws largely on EPRI research managed by Rolf Manfred of the Coal Combustion Systems Division.

Manfred's work centers on alternative fuels, with special attention to those that can be substituted for coal or oil in existing boilers. An EPRI project manager since November 1979, Manfred formerly worked at Acurex Corp. for 4 years in the design management of coal gasification, coal-oil mixture combustion, fluidized-bed combustion, and pollution control systems. Earlier, he was with Aerojet Solid Propulsion Co. for 18 years, where he became the director of advanced technology. Manfred holds BS and MS degrees in science from the University of Toledo.

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Variables in research settings, in data bases, in assumptions, in methodologies, and even in original research purposes—all have made for inconsistent findings about power lines and human health. But, as more and more data come from studies designed to reveal connections, the consistent message is that adverse effects cannot be discerned. **Electromagnetic Fields and Human Health** (page 14) is science writer John Douglas's review of recent research to categorize and measure typical human exposures, analyze epidemiologic data that link exposure and health effects, and identify biologic effects in chronically exposed laboratory animals. In covering that range of investigation, Douglas relied mainly on five EPRI research managers.

Robert Kavet came to the Health Studies Program of the Environmental Assessment Department in December 1978 and managed research on the biologic effects of electric fields during most of his stay there. He left EPRI in June of this year to join the staff of the Health Effects Institute, newly formed under EPA and automobile industry auspices to investigate vehicle emissions. Before 1978 Kavet was a graduate student and researcher at Harvard University for seven years, earning an MS in environmental health sciences in 1972 and an ScD in respiratory physiology in 1977. Also an electrical engineer, Kavet holds BS and MS degrees from Cornell University, and he worked at RCA Corp. for four years.

Gordon Newell has been senior manager of the Health Studies Program since he joined EPRI in September 1982. He was formerly associate director of the National Research Council's Board on Toxicology and Environmental Health Hazards. From 1950 to 1978 Newell was at SRI International, where he developed the department of toxicology and became its director. A chemistry graduate of the University of Wisconsin, Newell holds MS and PhD degrees in biochemistry from that university.

Ralph Perhac, director of the Environmental Assessment Department since 1980, joined EPRI in May 1976 as manager of the Physical Factors Program. For the two preceding years he was director of a National Science Foundation research program on the environmental effects of energy, and from 1967 to 1974 he was a professor of geochemistry at the University of Tennessee. Previously, Perhac was a field geologist for 15 years, working with mining and petroleum companies and the Atomic Energy Commission. He has BA and MA degrees in geology from Columbia and Cornell universities and a PhD in geochemistry from the University of Michigan.

Leonard Sagan, senior scientific adviser for the Energy Analysis and Environment Division since February 1982, joined EPRI in February 1978 to manage a program of biomedical studies. For 10 years before that he was a physician and associate director of environmental medicine at the Palo Alto (California) Medical Foundation. He first studied radiation effects and risk analysis during the 1960s as medical department chief for the Atomic Bomb Casualty Commission and as a research physician in nuclear medicine for the Atomic Energy Commission. Sagan earned an AB at Stanford University and an MD at the University of Chicago.

René Malès, an EPRI vice president, has directed the Energy Analysis and Environment Division since February 1976, when he came to the Institute from Commonwealth Edison Co. During the previous 20 years there, he worked largely in the financial and economic departments, becoming director of economic research in 1965. Five years later he was named assistant to the vice president of division operations, and in 1973 he became manager of general service. Malès graduated in mathematics from Ripon College and earned an MBA at Northwestern University.

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Among the world's seafarers, an occasional upriver port of call is always welcome. Fresh water kills the saltwater marine life that fouls a ship's hull and its condensers. For utility power plant operators, the analogous remedy of periodic chlorination may have environmental consequences, so new approaches are being investigated. **Keeping Biofouling at Bay** (page 22) was written by Nadine Lihach, the *Journal*'s senior feature writer, with guidance from EPRI's Winston Chow.

Chow specialized in water quality control for power plants even before he joined EPRI's Coal Combustion Systems Division as a project manager in February 1979. Formerly with Bechtel Power Corp. for more than six years, he became an engineering supervisor in the planning and design of water supply, treatment, and waste systems. Earlier, he worked briefly in polymer development at Raychem Corp. and in resin development at Sondell Scientific Instruments, Inc. Chow is a chemical engineering graduate of the University of California at Berkeley. He earned an MS in the same field at San Jose State University.

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Residential electricity conservation has been difficult for utilities to predict. Without good estimates of who would respond to an incentive, why, and to what extent, even the justifiable promotion effort could be anyone's guess. **REEPS: Simulating Residential Response** (page 28) explains how a lot of that guesswork is eliminated by an EPRI-sponsored national model recently adapted for individual utility use. This example of how research results are applied was prepared by science writer Stephen Tracy, aided by Steven Braithwait of EPRI's Energy Analysis and Environment Division.

Braithwait, a project manager in the Demand and Conservation Program, is responsible for research in residential energy forecasting and conservation analysis. He came to EPRI in July 1978 after five years as an economist with the U.S. Bureau of Labor Statistics. An Occidental College graduate in mathematics, Braithwait holds a PhD in economics from the University of California at Santa Barbara.

Chow

Braithwait

Manfred

Sagan

Newell Malès Kavet Perhac

OIL'S NEW RIVAL—COAL-WATER SLURRY FOR UTILITY BOILERS

Coal-water slurries have moved to the threshold of commercial production, offering utilities an alternative to burning oil for power generation. At least half a dozen producer organizations are now actively seeking a toehold in this emerging market.

Ever since the first Middle East oil embargo in 1973 shocked the West with the reality of petroleum politics, wide-ranging R&D efforts have focused on the search for alternatives to oil. Of all the alternatives pursued, the most promising near-term substitute for boiler fuel is among the simplest.

Composed of about 70–75% coal, 24–29% water, and 1% chemical additives, coal-water slurries (CWS) have a consistency similar to latex paint; because they are liquid, they can be stored, transported, and burned in essentially the same manner as fuel oil with certain equipment modifications. Such slurries are now at the threshold of commercial production, and some utilities are already laying plans to burn the liquid fuel in existing oil-fired boilers.

R&D progress with CWS has been unusually rapid, advancing from concept stage through pilot plant production in little more than five years. As recently as 1980 most utility engineers would have insisted that boilers designed and built to burn oil could not burn coal. Now, some utilities are beginning to rethink their approach to reducing oil consumption.

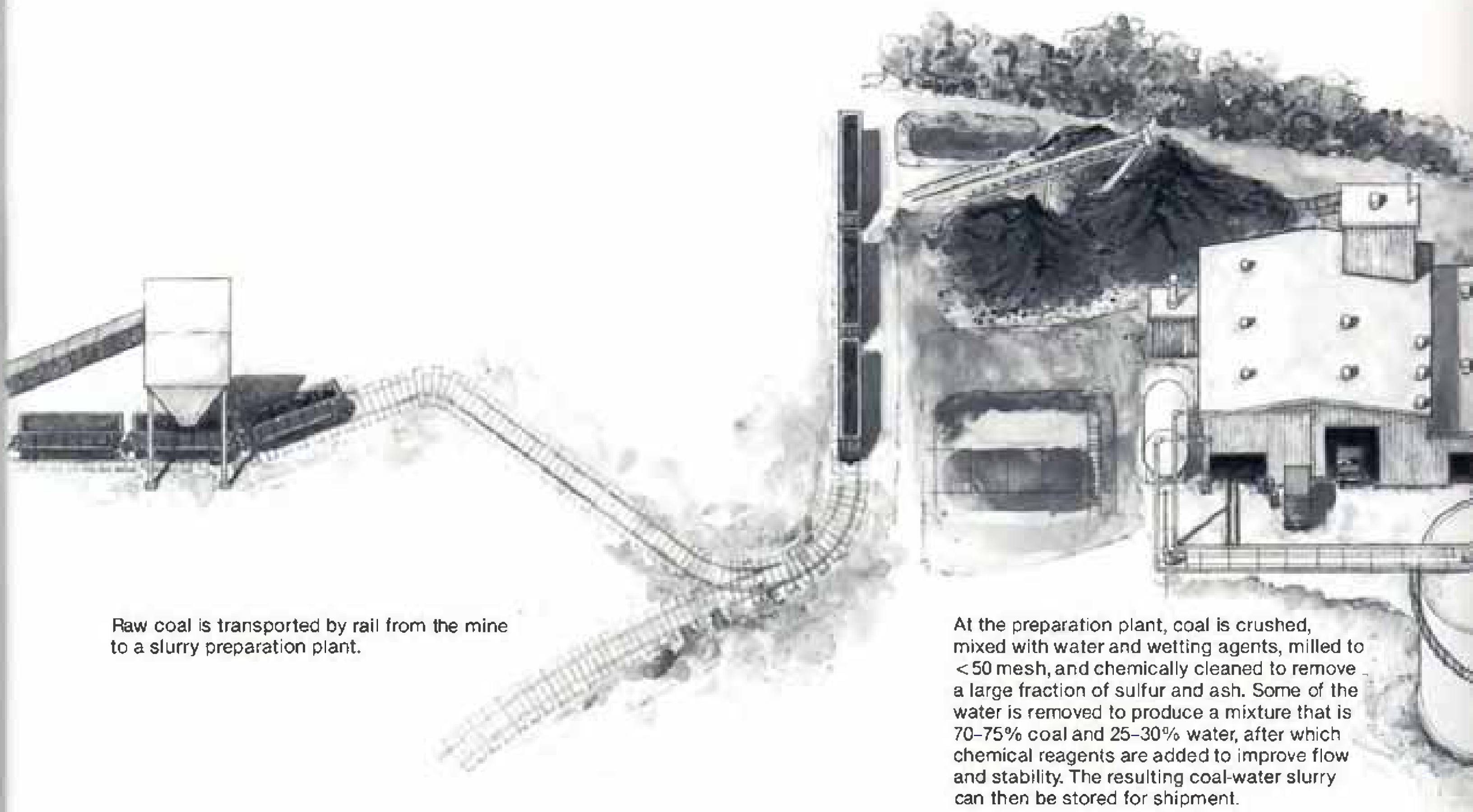
Immediate pressure for oil-to-coal conversion has generally waned in the United States as conservation and recession dampened energy demand and the price of oil slid from about $35 a barrel in 1980 to the present $28–$29 a barrel. Nevertheless, utility industry support of CWS development remains strong for a number of reasons.

Utilities probably will never again build oil-fired boilers for raising steam. As a matter of price, availability, and public policy, utilities have seen the writing on the wall. These signals were given added substance in 1978 with passage of the Power Plant and Industrial Fuel Use Act, which essentially prohibits oil use in new generating units.

When construction of new power plants does resume, the cost of coal-fired units will be high compared with costs for retrofitting existing oil-fired capacity, of which an estimated 200 GW exists—much of it underused and more than 80% of it less than 20 years old.

Aside from the insurance CWS affords against future oil shortages and the long-term trend of continuing oil price escalation, site-specific factors may favor conversion, such as the strong pressures applied to some East Coast utilities (especially in Florida) to reduce heavy dependence on fuel oil. Coal's more-stable price and smaller forecast price increases are important considerations for such utilities. Moreover, some utilities are contemplating the production and supply of CWS to other users as an opportunity for business diversification.

In the future, CWS that has been intensively cleaned may also be burned in



Raw coal is transported by rail from the mine to a slurry preparation plant.

At the preparation plant, coal is crushed, mixed with water and wetting agents, milled to <50 mesh, and chemically cleaned to remove a large fraction of sulfur and ash. Some of the water is removed to produce a mixture that is 70–75% coal and 25–30% water, after which chemical reagents are added to improve flow and stability. The resulting coal-water slurry can then be stored for shipment.

new plants to reduce sulfur emissions or used as fuel for advanced processes, such as gasification–combined cycles and pressurized fluidized-bed combustion.

Utility demonstration needed

Despite wide acceptance of the feasibility of coal-water slurry as a utility boiler fuel, CWS is not yet in commercial use. Combustion tests to date in small (10-MW) boilers have demonstrated that stable combustion flame can be maintained at full and partial loads, that the fuel can be made of consistent quality according to specifications, and that it can be transported, stored, pumped, and atomized much like No. 6 oil.

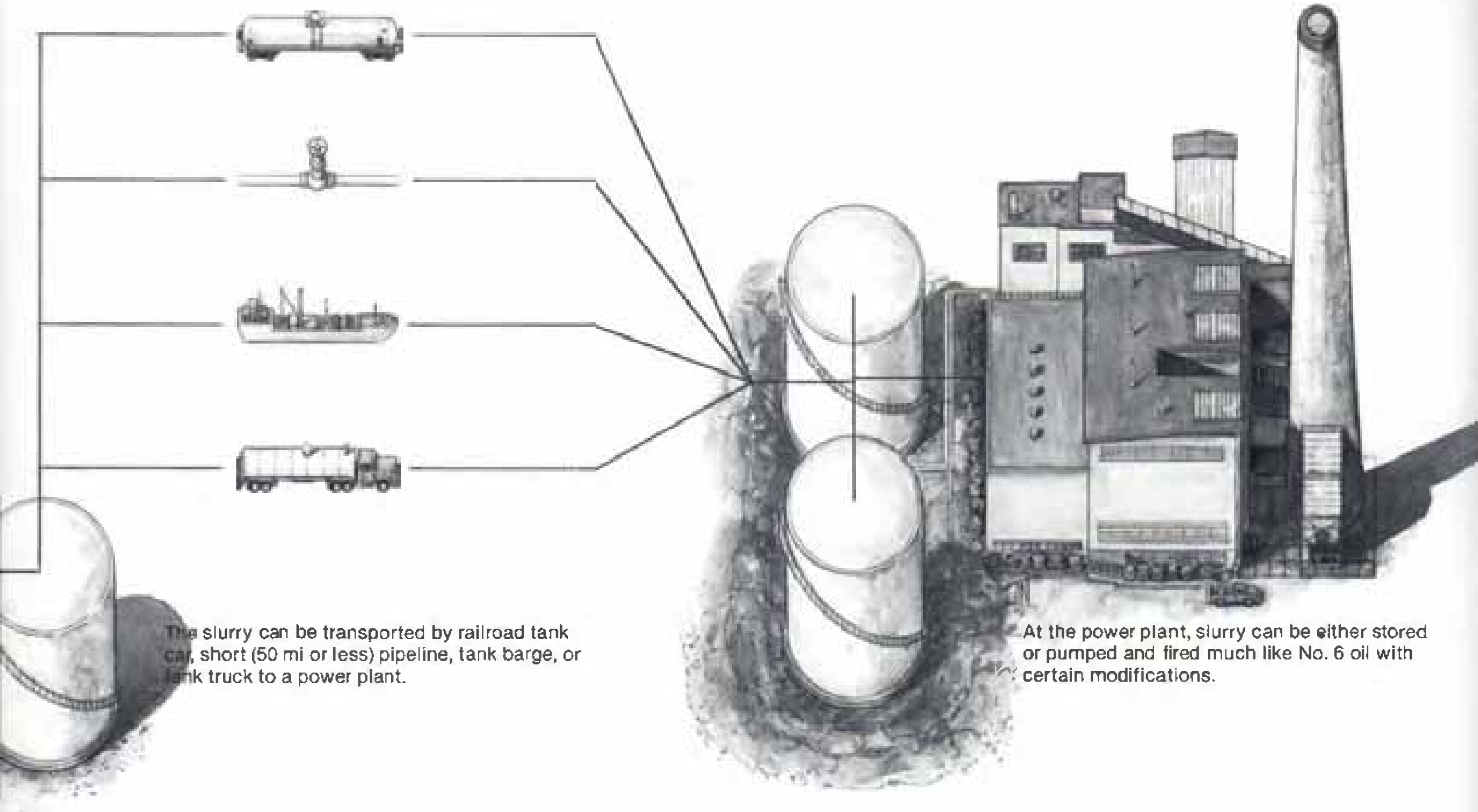
The effects of conversion on oil-design boilers have been predicted on the basis of limited tests, but experts believe an extended demonstration is needed in an oil-design utility boiler rated between 100 and 500 MW before CWS's technical reliability and economic advantages are confirmed. EPRI is considering participation in such a demonstration beginning in 1986.

"There are no major technical barriers remaining," according to Rolf Manfred, project manager for alternative fuels in EPRI's Coal Combustion Systems Division. "The problems that do remain seem to lend themselves to near-term, unheroic engineering solutions. The chief technical uncertainty for utilities is the degree of derating that an oil-design boiler will suffer by converting from oil to CWS. We need a large demonstration test to verify the derating predictions."

Conversion factors

The economic prospects of CWS appear promising, despite significant cost-related uncertainties that could dilute the fuel's appeal. Anticipated CWS prices, assuming a production level of 1 million t/yr, range from $2.80 to $3.50/million Btu; the range reflects the varying costs of coal feedstocks, processing, transportation, and coal cleaning that are required. At the high end of the cost range, which assumes intensive cleaning to remove ash and other impurities, coal feedstock represents about 46% of the cost; transportation from the mine, 17%; cleaning, 11%; and slurry preparation, 26%.

In comparison, current oil prices are running from $4.60/million Btu (at $29/bbl) to $5.60/million Btu. So, on a simple fuel cost basis, CWS is cheaper. Clearly, however, other factors add to the cost of firing CWS, such as boiler and plant modifications (including emissions control systems) and generating capacity loss from boiler derating. And as with oil, transportation costs must be considered—the cost of transporting CWS from the preparation plant to the user by railroad tank car, barge, truck, or pipeline. "When all these costs are considered," notes EPRI's Manfred, "the



The slurry can be transported by railroad tank car, short (50 mi or less) pipeline, tank barge, or tank truck to a power plant.

At the power plant, slurry can be either stored or pumped and fired much like No. 6 oil with certain modifications.

economic appeal of converting a boiler to fire CWS becomes a very site-specific question.

"Various estimates place the site-specific cost to convert an oil-fired utility plant from oil to CWS in the range of \$100–\$300/kW, if flue gas desulfurization [FGD] is not required," Manfred adds. Regulatory determination of whether a boiler conversion to CWS requires addition of FGD equipment represents a significant area of uncertainty, however. In 1980 EPRI estimated the potential cost of added environmental controls—particulate control (electrostatic precipitators or baghouses), SO_2 scrubbers, NO_x control systems, and solid-waste disposal equipment—that could be required for converting a boiler from oil to coal-based fuel at \$200–\$400/kW (1980 \$).

For a boiler designed to burn oil, the minimum modifications required to fire CWS include a steep furnace hopper bottom, deslaggers and soot blowers, new burners, larger forced-draft fans, and ash removal and handling equipment. The capacity of coal-capable boilers (i.e., boilers originally designed for pulverized coal but later converted to fire oil) may not be significantly affected by conversion to CWS, but the tight box configurations of some oil-designed units could potentially result in a capacity loss of as much as 60%. The degree of this capacity loss in site-specific evaluations clearly will be a major determinant of economic practicality.

Burns and Roe, Inc., has assessed conversion costs for two oil-fired boilers—one, a 460-MW tangentially fired, closed-coupled screen configuration, and the other, a 520-MW box-type boiler with a front wall firing system. The company estimated conversion costs at \$140/kW for the smaller boiler and \$217/kW for the larger unit; projected savings over a 15-year period from firing CWS rather than pulverized coal were \$40.7 million for the 460-MW boiler (derated to 390 MW) and \$48.5 million for the 520-MW boiler (no derating).

Burns and Roe's estimates were based on 1983 fuel prices of \$28/bbl for oil and \$3.50/million Btu for CWS, a fuel price escalation of 8%/yr, annual average plant capacity factors of 65%, and 15 years of remaining boiler life after conversion.

The study found that the economic competitiveness of CWS is strongly influenced by the cost of coal cleaning because the principal trade-off in boiler performance is the cost of reducing the ash content of the fuel. When incorporated in CWS preparation processes, advanced coal beneficiation techniques under development could significantly improve the economics of CWS fuel.

Numerous other calculations of conversion costs and capacity loss have been made by several architect-engineering firms and utilities, but the accuracy of these predictions can only be determined by a prolonged (one year or more) test in a sizable, oil-design boiler, according to Manfred.

Supply and demand

Such a demonstration and subsequent utility adoption of CWS as a boiler fuel will require assured availability of significant quantities of CWS. For the near term, it appears that a combination of price supports and private entrepreneurial investment will make an adequate supply of CWS available for a 400-MW boiler demonstration in 1986.

Once a large utility demonstration is completed, however, what will be the potential utility demand for CWS? The consulting firm of Hagler, Bailly and Co. conducted a survey in 1983 to estimate the market for CWS as an oil displacement fuel. It projected a minimum economic demand of about 200,000 barrels of oil equivalent per day, generating about 6000 MW. The base case assumed oil prices of $35/bbl in 1985 (1983 $), rising to $46/bbl in 2000. Projected demand represents that of about 20 individual utility boilers (most of them in New York, Massachusetts, Louisiana, and the Atlantic coast of Florida) that were placed in service after 1968 and have a normal life expectancy beyond 2000.

Demand for CWS could double by 2000, the study estimates, if oil prices double in that time and the CWS market expands to include California and West Florida. The market would also sharply increase if CWS can be produced for less than $3.50/million Btu; a drop as little as 15% in the price of CWS (to $3/million Btu) could double demand.

One cost factor with potentially significant bearing on a utility's decision to convert to CWS is that of transporting slurry from a production plant to the utility plant. Previous studies have considered the cost of transporting coal from the mine to slurry preparation plants constructed along navigable waterways. But the specific modifications to current transportation modes required to move slurry to utility users and the effects of those changes on transportation costs have not been examined.

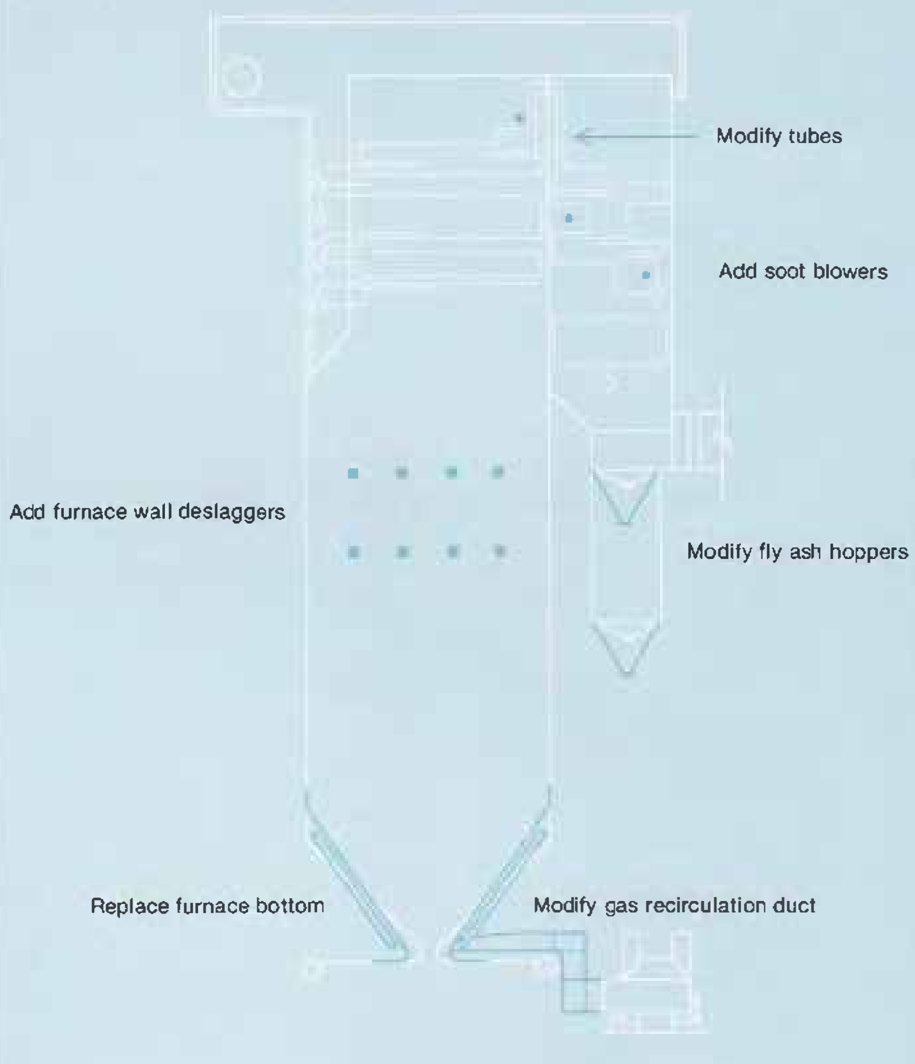
EPRI has initiated a project to compare technical and economic factors of alternative modes for CWS transportation, including barge, railroad tank car, pipeline, and tank truck. Generic technical evaluations of these modes will be conducted, as well as case studies of six potential utility sites to highlight the technical and economic trade-offs between different transport modes. The expected project results will be a set of guidelines that utilities can use to evaluate CWS transportation alternatives for various scenarios.

Characterizing slurries

CWS typically contains 70–75 wt% coal pulverized to 200 mesh or finer. Most slurries also contain about 1 wt% chemical additives that lend storage stability

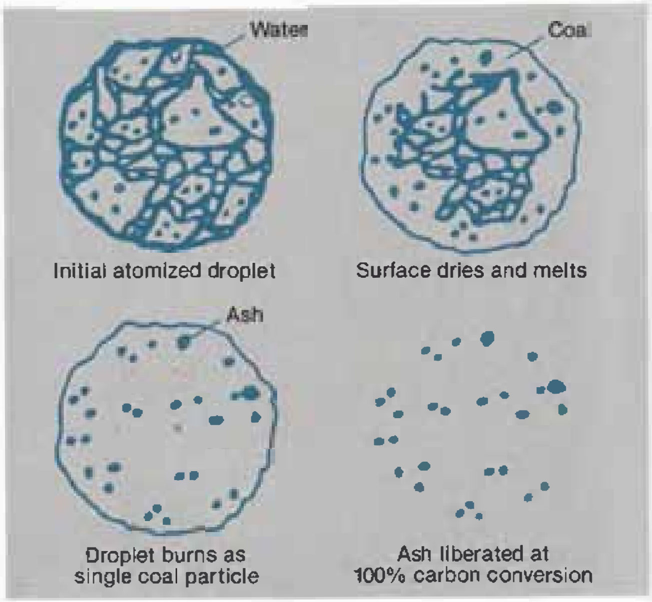
Boiler Modifications for CWS Conversion

Oil-fired boilers require some modification to burn coal-water slurry. To handle the higher ash content of coal-based liquid fuel, an oil boiler will require a steeper furnace hopper bottom, deslaggers and soot blowers, new burners, larger forced-draft fans, and ash removal and handling equipment. Depending on regulatory classification of coal-water slurry as utility boiler fuel, flue gas desulfurization equipment may also be required. The generating capacity of oil-design units probably will be derated by conversion to CWS.



Proposed Coal-Water Slurry Combustion Mechanism

Combustion tests with coal-water slurry are leading to improved understanding of the mechanism by which the liquid fuel burns. As the fuel is atomized, a single droplet of slurry containing many coal particles is formed. In the furnace, the droplet dries rapidly from the outside and melts into an agglomerate particle about the same size as the original droplet. As the carbon burns away, the particle becomes friable, resulting in a fine fly ash. The electron scanning micrograph shows one such particle after combustion. Research has highlighted the importance of atomization quality in slurry combustion efficiency. If atomizer droplets are too large (>300 μm), carbon conversion efficiency is impaired and the fly ash particles can be as large as the original atomized droplets.



COMMERCIAL DEVELOPMENTS TAKE OFF

Several producer organizations in the United States and Canada are scaling up pilot plant facilities to produce CWS, including such firms as Babcock & Wilcox Co.; Combustion Engineering, Inc.; Foster Wheeler Energy Corp.; Standard Oil of Ohio, Inc.; Occidental Petroleum Corp.; Atlantic Research Corp.; and Allis-Chalmers, Inc.

EPRI estimates that the combined production capacity of these suppliers by the end of this year will be around 350,000 t/yr. Government price supports or private development activity could boost this capacity to as much as 1.5 million t/yr by 1986.

A brief overview of recent commercial activity among CWS producers indicates that the pace of development is quickening.

Occidental Petroleum Corp. and Combustion Engineering have formed a joint venture to combine Occidental's coal slurry technology with C–E's boiler, burner, coal pulverization, and combustion experience. An Occidental slurry pilot plant in Jacksonville, Florida, is being scaled up to produce 110,000 t/yr of CWS.

Atlantic Research is producing CWS at a 40,000-t/yr plant at Fredricksburg, Virginia.

Advanced Fuels Technology, Inc., a subsidiary of Standard Oil of Ohio, is planning to increase CWS production from present pilot plant levels.

Babcock & Wilcox, Ashland Oil Co., and Slurrytech, Inc., are constructing a 120,000-t/yr CWS plant in South Point, Ohio. Plans called for startup by June 1984.

Allis-Chalmers last year signed a license agreement with Fluidcarbon International Ab of Malmo, Sweden, to produce and market coal-water fuel, together with associated burner equipment, in the United States. Allis-Chalmers has built a 40,000-t/yr mobile production apparatus for process demonstrations at various sites around the country.

Foster Wheeler and Ab Carbogel of Helsingborg, Sweden, have formed a joint venture to commercialize Carbogel's CWS. Carbogel fuel is now produced at a 40,000-t/yr plant in Sydney, Nova Scotia, Canada; the fuel is being test-fired at the New Brunswick Electric Power Commission's Chatham plant. Carbogel has proposed building a $25 million 500,000-t/yr commercial CWS plant in Nova Scotia. □

and desirable flow properties. The remaining fraction of the mixture is water, the minimum content of which is determined by viscosity considerations.

Although the proportions of these major constituents are important to the rheological, or flow, characteristics of a slurry, another, less controllable factor, is at least as important—the composition of the coal feedstock. Depending on where it is mined, coal contains 100–300 times the noncombustible organic matter of residual fuel oil, which causes fouling and slagging of boiler heat-receiving surfaces and thus degrades thermal efficiency.

To define the chemical characterization of slurries in more detail, EPRI contractors tested properties of CWS fuels from several slurry vendors. Heat content ranged 9,910–11,380 Btu/lb on an as-received basis and 13,800–14,600 Btu/lb dry; ash content, 1.7–9.2%; volatile matter content, 32.7–38.2%; sulfur, 0.67–0.81%; and viscosity of as-received slurries ranged 500–2000 centipoise (0.5–2.0 Pa·s).

Much of this variability can be addressed in the slurry preparation stage. For example, intensive coal cleaning, which can significantly reduce a slurry's ash and pyritic sulfur content, can be incorporated as an integral part of slurry preparation. Because the final product is liquid, the need (and cost) for drying—the final step in conventional coal cleaning—can be eliminated.

Because of a lack of standard test methods in the early development stages, however, the effects of process changes on CWS properties were difficult to determine, and direct comparison of different slurries was impossible.

In response, EPRI supported development of standardized laboratory test procedures for CWS fuels in conjunction with tests by Babcock & Wilcox Co. of six state-of-the-art slurries and their parent coals. An additional objective was to determine the relationships between slurry properties measured in the laboratory and their combustion and handling characteristics. As a result of the tests, guideline fuel specifications have been published and suggested analytic procedures for CWS characterization have been proposed to industry standard-setting technical committees.

Early laboratory-scale (1–5 million Btu/h) combustion tests of CWS fuels were important in relating coal parameters (such as particle size, volatile matter content, and ash chemistry) and conditions at the burner/atomizer (such as droplet size, spray configuration and fuel-air interactions).

One important consideration is the ability to maintain stable combustion while reducing or increasing fuel flow at the burner/atomizer as a means of controlling generating unit output. The tests demonstrated that densely loaded CWS (prepared from finely ground coal) could be fired successfully, but the tests required extensive combustion air preheat and indicated limited burner turndown capability, as well as low carbon conversion efficiencies (high 80% to mid 90% range).

Results highlighted the need for development of commercial-scale CWS burners that could handle the slower burning and more-erosive slurry fuels. Three domestic boiler companies—Combustion Engineering, Inc., Babcock & Wilcox, and Foster Wheeler Energy Corp.—have since demonstrated (the first two with EPRI support) atomizer/burner systems in commercial-scale boiler tests lasting several weeks. The burners ranged in rating from 15 million Btu/h to 80 million Btu/h. Although the tests resolved some significant uncertainties, improvements are still needed in atomization, combustion efficiency, and burner tip life.

To address these needs, a new generation of utility-scale (100 million Btu/h) burners is under active development. Performance goals include a turndown ratio of 3:1 or better, minimum tip life of 2000 h, air preheat of less than 300°F (149°C), maximum droplet size of 300 μm, and carbon conversion efficiencies greater than 99%. According to EPRI's Rolf Manfred, "Recent progress suggests that large burners meeting all or most of these goals will be available for testing this year."

In addition to burner equipment development, EPRI has supported analysis of the effects of CWS use on standard utility pumps designed to handle oil. The tests, sponsored in cooperation with Long Island Lighting Co., Empire State Electric Energy Research Corp., and New York State Energy Research and Development Authority, were performed at the Adelphi Center for Energy Studies on Long Island. They confirmed an important feature of CWS: certain oil-design pumps and storage facilities can accommodate CWS conversion with minimal modifications.

Combustion experience

Handling and combustion tests, each requiring the preparation and firing of several thousand tons of slurry and lasting for at least one month, have been performed in progressively larger boilers. Early tests in boilers of 8–20-MW capacity highlighted the need for prolonged tests in larger oil-design utility boilers to resolve performance uncertainties related to the considerably higher ash content of CWS over oil. Results of these tests have been applied in ongoing efforts to optimize burner designs and boiler operating conditions.

The largest-scale test conducted in the United States to date was sponsored by EPRI in 1983 at an industrial boiler operated by E. I. du Pont de Nemours & Co., Inc., in Memphis, Tennessee. Over 35 days, 2500 t of slurry were fired in a Stirling-type boiler capable of producing steam at 65,000 lb/h (8.19 kg/s). Three burners were used, each rated at 15 million Btu/h and modified with new atomizers and air register changes to produce a high-swirl, stable flame.

Slurries fired in the test were prepared by Atlantic Research Corp. in Virginia and Slurrytech, Inc., in Pennsylvania. The fuel was shipped 1000 mi (1600 km) to Memphis in 100-t railroad tank cars, pumped into tank trucks for transfer to a 15,000-gal (57-m^3) agitated day tank, and stored for as long as 14 weeks without stratification of the slurry.

Nearly maximum boiler load was achieved when firing slurry in three of five burners; flames were clear and stable, but burner tip erosion became severe after six or seven days of continuous firing. Ash buildup in the furnace was observed to be minimal during normal operation; slag was easily removed with soot blowers. Although successful as an operations test, the demonstration was performed with high-quality coal and under nearly constant monitoring.

The next step in proving CWS's commercial readiness, researchers believe, requires a year-long demonstration in a utility-scale boiler rated between 100 and 500 MW. Burns and Roe, under EPRI contract, is evaluating some 40 oil-design candidate generating units of 18 utility companies. The contractor is performing feasibility studies of each candidate boiler and providing utilities with conceptual modifications, as well as estimates of retrofit and operating costs for a one-year demonstration.

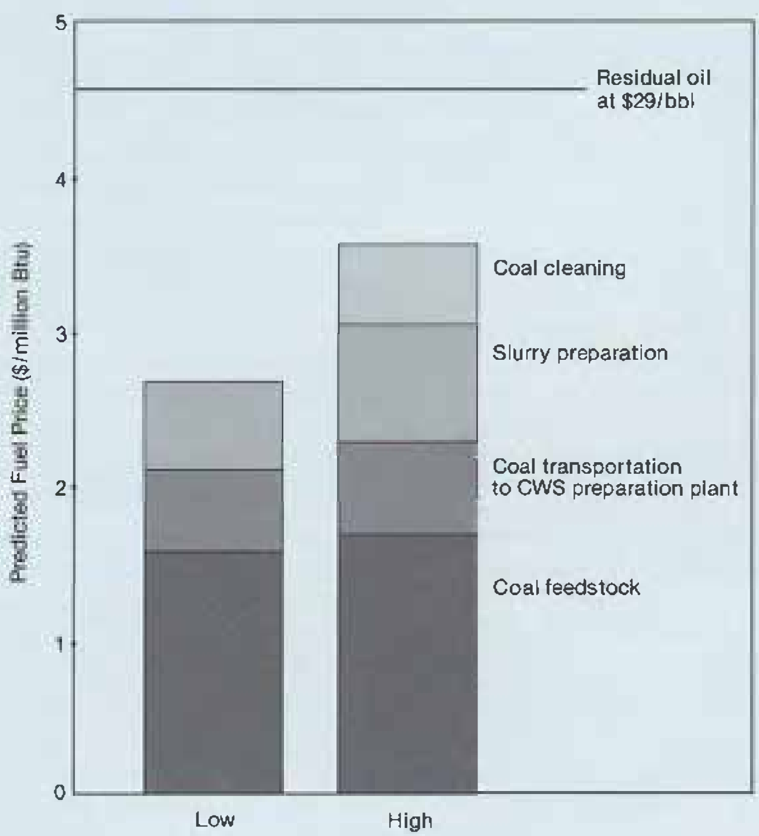
Selection of the demonstration site is expected in 1985; a year's work will be required to retrofit the plant for firing CWS. Actual testing could begin in

1986. The scope and level of EPRI's support for the demonstration may be determined by the end of this year, according to Manfred.

In the meantime, some utilities are independently planning CWS demonstrations. Florida Power & Light Co. has announced plans to convert its 400-MW oil-fired Sanford Unit 4 to fire CWS. A 20-MW utility oil boiler demonstration of CWS is planned for later this year in Charlottetown, Prince Edward Island, by a group of electric utilities in Canada's Maritime provinces. EPRI expects to be involved in the Canadian effort in an advisory capacity.

CWS Cost Predictions

The cost of coal-water slurry, when manufactured in a production plant at a rate of 1 million t/yr, is projected to range from \$2.80 to \$3.50/million Btu. The range reflects different coal feedstocks, coal transportation costs, and the cost of coal cleaning. Production cost compares favorably with residual oil at \$29/bbl, but does not include various added costs of firing coal-water slurry, including boiler modifications, slurry transportation to the boiler, and (perhaps) flue gas desulfurization equipment.

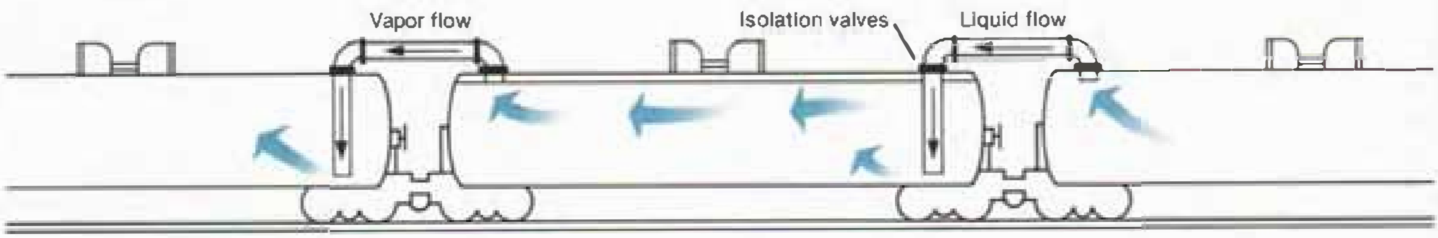


Questions remain

Two significant areas of uncertainty continue to cloud the otherwise bright outlook for CWS: the availability of capital to spur the scale-up of slurry production capacity and regulatory determinations on emissions control requirements for oil-fired plants converted to fire slurry.

With respect to the first area of uncertainty, the U.S. Synthetic Fuels Corp. (SFC) has issued a solicitation for proposals that may result in price support contracts to slurry vendors. Proposals were due to SFC in June 1984; SFC anticipates completion of the projects in 1987. The corporation reportedly intends to make two coal-water fuel project awards: one for a project producing at least 1000

Coal-water slurry can be transported from the preparation plant to utility plants via tank truck, railroad tank car, pipeline, or barge. For an EPRI-sponsored combustion test at an industrial boiler in 1983, slurry from producers in Pennsylvania and Virginia was shipped 1000 mi (1600 km) to Memphis, Tennessee, in 100-t railroad tank cars. In a trial of the tank train concept, three-car segments were connected by pipes to permit continuous loading and unloading under 25 psi (170 kPa) air pressure. EPRI is evaluating the technical and economic factors of possible transportation modes.



bbl/d oil equivalent for use in industrial boilers and the other producing at least 3000 bbl/d for firing in electric utility plants.

Each of the awards is anticipated to provide CWS price supports that would enable the contractors to sell slurry substantially below the price of No. 6 oil and still recover their investment over the duration of the contract. The low initial price of CWS should encourage some utilities to invest in the required plant modifications and take the risk of pioneering the full-scale use of coal-water slurry.

These subsidies could increase domestic CWS production capacity to 1.5 million t/yr by the end of 1985 or early 1986. SFC's schedule for negotiating contracts with slurry vendors generally coincides with EPRI's planned timetable for demonstrating CWS firing in a large (400-MW) utility boiler. Without SFC support, it is expected that current commercial plans to increase CWS production capacity to about 500,000 t/yr will limit either the size of boiler chosen for a demonstration or the time available to conduct the necessary tests.

The uncertainty of environmental and regulatory requirements for CWS use is potentially a major obstacle to widespread use of coal-water slurries. Most utilities will not proceed with CWS conversion plans on a permanent basis (or even for limited testing) until the requirements and costs of emissions control are more clearly defined.

The key issue is whether conversion of an existing oil-fired generating unit to burn CWS represents a major modification of the plant and thus makes it subject to EPA's New Source Performance Standards. In 1978 EPA's Office of Air Quality Planning and Standards stated that oil boiler conversions to coal-oil mixtures, coal-oil-water mixtures, and solvent-refined coal would not constitute major modification under existing law and therefore would not be subject to standards applied to new facilities.

In response to specific inquiries on coal-water slurry, however, in 1983 the same office indicated that individual state environmental agencies would set the rules for CWS emissions. As matters now stand, utilities must address this issue individually according to widely varying state regulations.

Of the utilities under consideration as hosts for a one-year CWS demonstration, none has an electrostatic precipitator capable of handling CWS particulate emissions on a long-term basis without costly modifications, and some have no particulate control equipment in place.

Oil-fired units converted to burn slurry in a one-year demonstration probably would require an emissions variance. If scrubber systems for desulfurization are required for CWS retrofits as well as for conversion to pulverized coal, according to Manfred, conversion economics shift toward pulverized coal or even favor continued use of oil or gas.

At the threshold

Rapid progress in CWS R&D, substantially supported by EPRI, has brought the fuel oil substitute to the threshold of commercial production and use. The remaining technical issues are considered resolvable, and other significant uncertainties are likely to be resolved, or at least clarified, in the near term. Many utilities are expressing strong interest in the future use of CWS, and it is likely that at least some of the nation's oil-fired generating capacity will be burning CWS by decade's end. The question now seems to be how rapidly the CWS market will grow. ■

Further reading

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This article was written by Taylor Moore. Technical background information was provided by Rolf Manfred, Coal Combustion Systems Division.

Electromagnetic Fields and Human Health

For more than a decade, questions have been raised about possible health risks associated with long-term exposure to electric and magnetic fields. An extensive, ongoing research program has begun to provide some definitive answers.

Specially designed vests measure the cumulative exposure to various field strengths from high-voltage power lines as a farmer goes about his daily activities. An electrically conductive cloth overlay on the vest is attached to monitoring instrumentation.

Electric and magnetic fields surround us. They are given off by all household appliances, power lines, and even the earth itself. No obvious harm has resulted from nearly a century of public exposure to the fields from electric power sources and from decades of using electronic equipment. The health effects, if any, that result from normal exposure to these fields are therefore probably very small.

Now, for economic and engineering reasons, electric utilities face an increasing need to build new, very high voltage transmission lines. Such lines offer great advantages for carrying large amounts of power from generating plants located near natural resources to customers in distant urban areas. A single 765-kV line, for example, can carry as much power as thirty 138-kV lines at one-tenth the construction cost and with only one-thirteenth the amount of right-of-way land required per kilowatt. Such lines do produce more intense electromagnetic fields at ground level, however, and the question of possible health effects from public exposure to these fields has arisen increasingly in regulatory hearings on the siting of new high-voltage transmission lines.

Over the last few years there have also been scattered, but persistent, reports that long-term exposure to fields from power lines may, under particular conditions, produce subtle biologic effects. Recent experiments in cell biology (discussed later) have also indicated that even low-level fields may affect the biochemical activity of some body tissue. Such findings have raised new questions about how field exposure may affect human health.

Because of the questions raised by recent scientific studies and the concerns expressed about high-voltage power lines, EPRI has become a leading sponsor of research on the biologic effects of electric and magnetic fields. This work is being conducted by various research organizations, including Battelle, Pacific Northwest Laboratories, Enertech Consultants, and Electric Research and Management, Inc. The objectives of this work are to measure human exposure to fields more precisely, to understand the meaning of epidemiologic studies that suggest a possible connection between such exposures and human health, and to determine whether chronic field exposure can create detectable effects in laboratory animals.

Research so far suggests that routine exposure to electromagnetic fields, including those from transmission lines, does not present a public health hazard. More specific data about exposure levels and field effects will be needed, however, to quantify any possible risk and put it in a proper perspective. EPRI is cooperating with the U.S. Department of Energy (DOE) to gather the information on biologic effects that will eventually be used to make quantitative risk assessments.

Pinning down exposures

Measuring the intensity of electric and magnetic fields near a power line or appliance is straightforward; estimating the duration of human exposure to particular field intensities is not. For this reason, most earlier studies have not included actual measurements of human exposure to fields. The problem is that people come and go, constantly changing their proximity to the sources of fields. Posture and surroundings can affect exposure—a farmer walking under a power line experiences its field more strongly than one bending over or standing in shoulder-high corn. Frequency also matters. Power lines produce almost exclusively a 60-Hz field, but appliances like TVs and home computers give off harmonic fields containing much higher frequencies. All these factors have to be taken into account in order to determine whether exposure to fields may affect human health.

The main problem in determining instantaneous exposure is that any conducting object placed in an electric field distorts it. The maximum unperturbed strength of an electric field under a 765-kV transmission line is about 10 kV/m at the height of a man's head and falls off rapidly to less than 2 kV/m a couple of hundred feet on either side. But a tall, thin object, like a standing man, bends the field so it is much stronger near the top end (lightning rods offer an extreme example). Thus the field strength actually measured at the head of a man standing under a 765-kV transmission line will be higher than 10 kV/m. Conversely, a man riding in the closed cab of a tractor moving under the line will experience less than 10 kV/m at his head, because of the vehicle's shielding effect.

Prior to current research, virtually no data were available on which factors were the most important in determining exposure. Rather, field exposures were calculated by using assumptions that caused them to be quite high, compared with actual exposure data now being collected. These new measurements were funded by EPRI's Environmental Assessment Department. With assistance from more than a dozen member utilities, Enertech and General Electric Co. measured actual field levels experienced by a person performing several different kinds of activities and used these data to determine typical exposures of an important group of workers—farmers tending crops under transmission lines. The methodology developed during this research, the activity systems model, is now available for use with other exposed groups.

The key to the methodology is an activity factor, defined as the ratio between the exposure measured during some activity (like riding a tractor) and the exposure that would have been experienced by the same person standing erect on wet grass with wet shoes (thus maximizing field distortion). Measurements were made by using instrumented vests specially constructed for this experiment. Conductive cloth containing stainless steel yarn was sewn over commercially available vests or jackets and attached to electronic units that can measure cumulative exposure to five levels of field strength. Activity factors were measured for such farm activities as horseback riding (the rider received an average of 82% of the exposure he would have experienced from standing in wet grass at the same spot), working bent over in knee-high grass (52%), and sitting on an open-top tractor surrounded by waist-high (1-m) vegetation (30%).

From these activity factors and studies of how many hours farmers spend in various activities, annual time-exposures were calculated for work on 18 typical farms (as defined by the U.S. Department of Agriculture) crossed by different voltage classes of transmission line. On farms crossed by a 345-kV line, for example, cumulative exposure averaged only 60 (kV/m) · h per year, equivalent to experiencing a 10-kV/m field for 6 hours a year, or a 1-kV field for 60 hours a year. Actually, 90–98% of the farm work exposure came from contact with low-level fields having about the same intensity as those found in typical houses. For comparison, the study found that the average cumulative exposure at home was 70 (kV/m) · h per year. More than half of this domestic exposure was from using electric blankets, with television sets, light dimmers, and household appliances making up the balance. (Such exposure levels are on the order of 1000 times less than those experienced by animals in laboratory studies.)

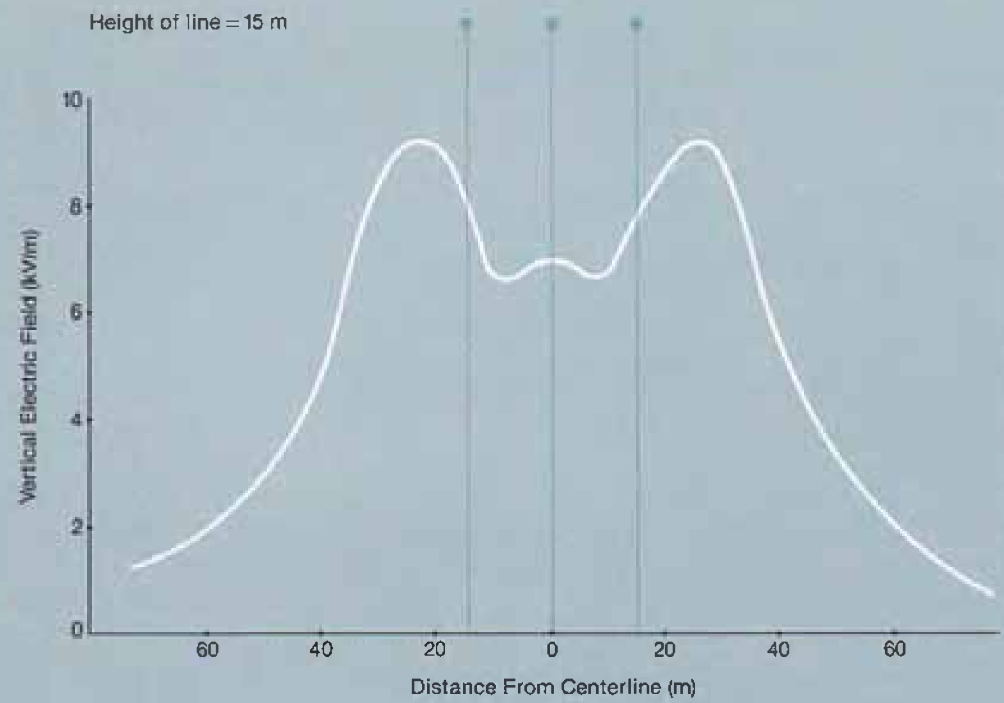
Another group receiving particular attention are utility employees who are exposed to electric fields during the course of their work. Some of these workers participated in a pilot study in which they wore another type of device, which was developed by the Bonneville Power Administration. Called an EFEM (electric field exposure meter), this multichannel electronic instrument is about the size of a cigarette package and is designed to be worn in a shirt pocket, on a lanyard around the neck, or on a hard hat. Research with this instrument is still in progress, but data collected so far indicate that electric utility workers generally receive much less cumulative field exposure than previously thought. For example, BPA data suggest that on a daily basis electricians usually receive less than 10 minutes of exposure to field intensities greater than 2.4 kV/m. The efficiency of EFEM is still in question, however, and more work will be needed to determine how changes in a worker's activities affect the data.

Another project, sponsored by the Electrical Systems Division, aims at determining more precisely what kinds of fields people may encounter from various sources in their homes. Instruments used in this study monitor electric and magnetic fields over a wide spectrum of frequencies, not just the 60-Hz fields measured by the experiments with the instrumented vests. Preliminary data indicate that the fields near operating TV sets, home computers, and light dimmers are higher than those directly under nearby distribution lines. Such data cast doubt on previous attempts to estimate field exposures inside a house from proximity to outside distribution lines. Also, the fields emitted by household appliances were found to include higher frequencies that may be more readily absorbed by the human body than the relatively pure 60-Hz field given off by power lines.

Epidemiologic studies

Such exposure data can help put some recent epidemiologic studies into perspective because none of these has been based on actual measurements of exposure to fields. Much of the current controversy resulted from a decade-old study of Soviet switchyard workers who reported that they began to experience loss of appetite, listlessness, and diminished sex drive after long-term occupational exposure to high-voltage fields. Despite the ill-defined nature of these symptoms and a lack of corroborating evidence, the Soviet Union responded by setting time limits for exposure to electric fields greater than 5 kV/m.

Other studies of electrical workers have been conducted in Canada, England, France, Italy, Sweden, the United States, West Germany, and elsewhere over the last 20 years. None of these has confirmed the findings reported from the Soviet Union. In Sweden, for example, Exposure to electric fields produced by high-voltage transmission lines is, in large part, a question of proximity. Shown is the field produced by an overhead 765-kV line, measured at 1.5 m above the ground. The field strength rapidly falls off with distance from the line—from a peak of about 9 kV/m at 20 m from the center of the right-of-way to less than 1 kV/m at 80 m.



53 utility linemen with long experience working around high-voltage lines were studied, together with a control group, to see whether any physical or mental health effects could be attributed to field exposure. No such effects were found.

Some western researchers have questioned the Soviet findings, pointing out that it would be hard to account for the specific effect through known biologic mechanisms. Also, switchyards contain many other environmental factors besides electric fields that could cause the health problems cited by the Soviet workers, including noise, oil fumes, and a variety of chemicals. Eventually, as more and more researchers failed to find similar effects, the furor created by the Soviet study died down. However, the issue was raised in regulatory hearings, and EPRI and DOE launched major long-term research programs to study possible effects.

Then in June 1979 a paper appeared in the *American Journal of Epidemiology* that helped trigger a new round of research into the possible connection between human health and exposure to fields from power lines. The paper presented a study conducted by Nancy Wertheimer and Ed Leeper of the distribution line configuration near homes of children who died of cancer in the greater Denver area. Homes were classified according to whether nearby lines were considered a high-current configuration (HCC) or a low-current configuration (LCC). The former was assumed to produce higher magnetic fields inside the homes.

The researchers found that for children whose residences had remained stable, 44% of the cancer victims lived in HCC houses, compared with only 20.3% of a control group. For children who had moved, the difference was less dramatic but still showed a larger proportion of HCC houses for those with cancer. The authors concluded that the presumably higher magnetic fields in the vicinity of a HCC line might somehow have caused the higher incidence of cancer, but they could not identify a mechanism.

When a group of researchers from Brown University attempted a similar study in Rhode Island, they found no evidence of the reported relationship between cancer and distribution line configurations. At each of four presumed levels of exposure to fields, the proportions of cancer victims and controls were virtually identical.

Neither of the studies used actual exposure data. Recent measurements of fields produced in homes by household appliances indicate that these probably contribute more to human exposure than power lines inside or outside the home, but that cumulative exposure from all sources is quite low. Both studies, moreover, had other serious methodology problems, which have been analyzed for EPRI by H. Daniel Roth Associates, Inc. This analysis concluded, in part, that Wertheimer and Leeper had failed to consider other potential causes of cancer, such as pollution, genetics, and diet; that the selection of controls may have been biased; that the researchers failed to consider possible combined effects of other variables, including neighborhood, traffic, and sex; that it appears no adjustments were made for family cancer patterns; and that addresses were chosen inconsistently. The Roth analysis concluded that the Brown University group also failed to consider other potential causes of cancer; that subjects and controls were not matched for potentially critical factors, including sex and family patterns; that only birth addresses (not current addresses) of controls were considered; and that there were other specific problems in the data analysis.

Over the last two years, further epidemiologic studies have fanned the controversy. One Swedish group claimed to confirm the Wertheimer-Leeper findings. Separate studies of cancer within electrical occupations in Washington State and Los Angeles indicated that the incidence of leukemia among power station operators, linemen, and motion picture projectionists who work near transformers was two to three times higher than among other workers. Similar studies of electrical workers in Great Britain reached much the same conclusion. Again, occupational exposures to fields were inferred from the nature of the work, and none of the studies was able to rule out the possibility that other environmental factors might be involved.

"Epidemiologists look at differences in the frequency of a disease between two populations to determine which factors might contribute to disease, but association alone cannot be treated as conclusive evidence of causation," says Leonard Sagan, senior scientist in EPRI's Energy Analysis and Environment Division. "Only after a study has been repeated under a variety of conditions can an epidemiologist conclude that exposure to a particular agent causes a given disease. If the Wertheimer-Leeper conclusions were valid, magnetic fields would be among the most powerful carcinogens known, and there would be an epidemic of childhood cancers. We would easily to able to detect such an effect, but instead, we see the opposite: the evidence of childhood cancers is decreasing. Still, the recent series of papers revealing higher incidences of cancer among certain residential and occupational groups exposed to electromagnetic fields deserves careful consideration. The cause of these cancers may have nothing to do with fields—leukemia, for example, tends to correlate strongly with socioeconomic status. Nevertheless, we have an enormous obligation to pursue the matter."

Animal experiments

Basic research in cell biology, using tissue cultures exposed to electric and magnetic fields, has recently provided useful in-

CONTROVERSY OVER HV TRANSMISSION LINES

Between 108,000 and 130,000 mi (173,800–209,200 km) of new transmission lines will be needed in the United States before the turn of the century. Whether the actual figure is closer to the upper or lower end of that range depends largely on what kinds of lines are built. Not permitting utilities to use transmission voltages of 765 kV and above would result in 21% more line, 22% more right-of-way, and 16% more peak energy loss at an additional cost of about $3 billion. Much of the debate over whether to allow such lines now centers on the issue of biologic effects of electric and magnetic fields.

This issue first came to a head during the early 1970s at regulatory hearings in New York State. An application to construct a 150-mi (240-km), 765-kV transmission line resulted in 72 days of hearings that produced approximately 14,000 pages of testimony—much of it related to possible health effects from various causes, including exposure to fields. Approval to build the line was finally granted in June 1978, and the hearings helped resolve public concerns over some health issues. However, the question of exposure to electric fields continued to be raised.

When construction began on a ±400-kV dc line in Minnesota and North Dakota in 1977, local opposition was intense. Vandalism and violence occurred throughout the construction period. Fifteen lattice steel towers had been destroyed along the Minnesota segment of the line by the end of 1981, and security costs had risen to about $4.8 million. After the line was energized in late 1978, nearby residents began to complain of health problems they believed resulted from living near the line. These problems included nosebleeds, fatigue, miscarriages, skin irritations, and stress.

In response, the Minnesota Environmental Quality Board (MEQB) initiated an inquiry to determine what health effects might result from exposure to the electric field and to small air ions created by the line. A science advisers panel concluded that there was no scientific basis to the belief that either fields or ions produced by the line would pose a hazard to human or animal health. Meanwhile, researchers from the University of Minnesota reviewed records of the Dairy Herd Improvement Association and concluded that the line had no apparent effect on milk production or herd reproduction. Reflecting these findings, MEQB decided that no further action was required to protect public health and safety.

During all the hearings and reviews, however, scientists expressed the need for more definitive data. The lack of such data also probably contributed to continued public concern over the effect of high-voltage lines. The results of ongoing EPRI research to measure actual human exposures to fields and to determine field effects in laboratory animals are helping fill some of the critical gaps in information. □

sights about how fields may affect living organisms. The primary interaction of a field with the biologic material appears to take place mainly at the cell membrane, rather than inside the cell. These membranes control a host of functions, including the transport of ions into and out of a cell. Fields with particular frequencies and intensities can apparently alter this transport, which may disrupt the cell's biochemical activity or responsiveness to chemical signals. Such findings suggest that scientists studying whole animals exposed to fields should look particularly for changes in hormone binding or other processes mediated by cell membranes. They also suggest that changes in heredity (encoded by DNA in the cell nucleus) would be less expected. Indeed, electric fields have shown no mutation-producing activity at the cellular level.

Most previous studies of animals exposed to even high levels of electric and magnetic fields, however, have failed to produce noticeable changes in health or bodily function. Several reasons have been suggested to explain why effects observed at the level of cells have not shown up as clearly in whole organisms. The fields induced inside whole animals are much less than those used to expose cell cultures in laboratory experiments. Also, the body may be able to compensate for any changes that do occur in particular cells. To find out and to determine once and for all whether fields can affect health, experiments with laboratory animals are needed to provide dose-response data relating exposures to biologic effects.

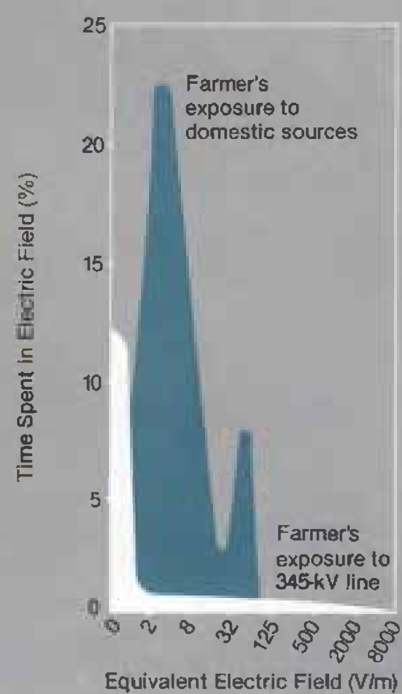
Designing such experiments is difficult. Because the effects are not easily detected, large numbers of animals must be exposed to very high field levels for extended periods of time. Just as building materials are severely stressed to determine how well they can stand up under ordinary circumstances, subjecting laboratory animals to unrealistic exposures to fields is an accepted way to determine confidently whether such fields may cause overt or subtle harm at various exposure levels.

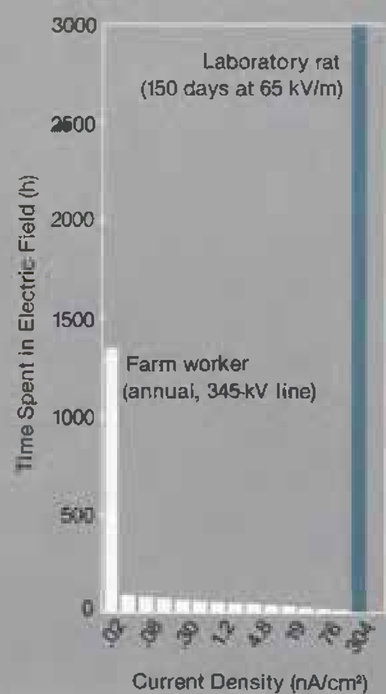
In 1978 a large-scale EPRI-sponsored experiment began at Battelle's laboratories in which Hanford miniature swine were exposed to 60-Hz electric fields for months at a time. These swine were chosen because an adult pig in this breed weighs about the same as an average man and has other physiologic similarities to humans. To simulate as closely as possible the electric field a human would experience when standing beneath a 765-kV power line, the swine were exposed to fields of 30 kV/m. This field produces approximately the same surface field on top of a pig as a man would experience at the top of his head in the 10-kV/m field produced by the line. The currents induced inside their bodies, however, are somewhat different, and the pigs can feel the 30-kV/m field, whereas most people cannot feel the field below a power line.

Two specially designed barns were constructed to house the field-exposed and control groups of female swine. An overhead electrode in the barn with exposed pigs generated an electric field 20 hours a day throughout the duration of the experiment—the equivalent of a human standing directly under a 765-kV line almost all day every day. (The field had to be turned off 4 hours each day

Left: People are subjected to electric fields in the home from such sources as kitchen appliances, TV sets, electric blankets, and even common lamps and lighting fixtures. Studies of farmers who are subjected to fields from both domestic sources and power lines sited on their property show that the great majority of their outdoor working time is spent at levels lower than they would receive from watching TV (3 V/m). Only about 5% of their working time is spent in field strengths higher than those given off by household appliances.

Right: In laboratory studies to assess possible biologic effects of high-voltage fields, test animals are subjected to extremely high field strengths for extended periods of time. In one series of experiments, laboratory rats were exposed to electric fields on the order of 65 kV/m, 20 hours a day for 150 days. The annual occupational exposure of a farm worker in the vicinity of a 345-kV line is on the order of 1000 times less than that of the test animals.





to allow for data collection and routine cleaning of the barn.) Three successive generations of swine were studied to see whether they experienced any detectable effects in the areas of behavior, blood chemistry, cytogenetics, endocrinology, growth, hematology, and reproduction and development.

Even at this high exposure level, no significant differences were found between the exposed and control groups for most of the factors studied. However, contrary to what might have been expected from the cell biology experiments, some differences were suggested in reproduction and development. During the second breeding of the first generation of swine, the litters of exposed sows experienced a higher incidence of fetal malformations than did those of the control sows. No such effect had been observed during the first breeding. When the second generation sows were bred, just the opposite happened. The incidence of fetal malformations was higher among litters of exposed sows during the first breeding, but no difference between the two groups occurred during the second breeding.

Interpreting these results was difficult for three reasons. First, Hanford miniature swine have malformation rates that are high and quite variable, compared with other laboratory animals. As a result, the reproductive differences between exposed and control groups could not be confidently resolved with the relatively small number of litters observed in the experiment. (Only a few dozen breeding sows could be housed at any one time.) Second, although the differences observed between the groups were judged statistically significant (i.e., not likely to be attributable to random effects), not enough information was available to conclude

Laboratory and field research on the biologic effects of electric fields has concentrated on a number of species over the years. Information on plant growth and leaf damage was developed primarily from greenhouse experiments. Animal studies have ranged from research on chicken egg development to investigations of the growth and reproduction of animals as large as swine. Experiments with bees have looked at behavioral effects on a complex social structure. Future research is likely to focus on rats, which have a good track record as a laboratory species and a sufficiently short gestation period to allow for a large number of reproductive cycles in a reasonable test period.

that these differences were due to the presence of the electric field. Third, even if the presence of a field did cause the observed effects, it would still not be clear if they resulted directly from the high-level exposures or if chronic perception of the field created a reaction in the exposed sows. This question has yet to be tested, but another experiment showed that if given a choice, the swine preferred to remain away from the field.

When a team of three independent teratologists were asked to visit Battelle and review the swine data, they concluded that the study had not conclusively demonstrated the existence of a relationship between electric field exposure and fetal malformations. Although the teratologists agreed that the experiments were conducted according to high scientific standards, two of them noted that environmental factors may have been stressful enough to the pigs to affect the results. "The high incidence of malformations in both the controls and the experimental animals may have been due to the long-term inbreeding of this strain of miniature swine," explains Gordon W. Newell, manager of EPRI's Health Studies Program. "It's hard to determine whether or not an effect exists when there's such great variability and a high background incidence of teratologic problems in the test animals."

Repetition with rats

To resolve some of the questions raised by the swine research, the Battelle researchers began to repeat the experiments with another, smaller species that could be tested for field effects. Failure to obtain similar results would indicate that the effects seen in swine might be species-specific or merely a chance occurrence. On the other hand, if the smaller, more quickly bred species also experienced reproduction and development effects after exposure to a field, then the experiment could be repeated with a large number of animals to provide better statistical analysis.

Following this logic, the Battelle team repeated the protocol of the swine experiments with rats, which have a gestation period of only 21 days, compared with nearly 4 months for the pigs. Total time for a breeding experiment would thus take months instead of years, and the rats could easily be raised in larger numbers. The schedule of experimental events that had been used with the pigs was therefore repeated twice, using roughly twice the number of female rats as there had been sows in each breeding.

But again the results were ambiguous. During the first repetition of the experiment, the second generation of exposed female rats showed a higher incidence of fetal malformations in their second litters than the control group. This result was similar to that observed in the swine. During the second repetition of the experiment, however, the litters from the exposed and control groups of rats were equivalent.

Such contradictory results have been frustrating for the Battelle researchers, who have been working on this project for more than seven years. The results of the experiments are nevertheless important, according to EPRI Project Manager Robert Kavet. "Of course, we would have preferred that the results were unambiguous," he comments, "but they clearly demonstrate that even exposure to worst-case levels of electric fields—levels perceptible to the experimental animals—cannot produce consistent effects. Obviously, no human mother is going to experience anything like this extreme level of exposure, and so our judgment is that the phenomena observed in the laboratory cannot be taken to imply a risk to human health from ordinary encounters with fields from power lines."

Directions for the future

Now that reproduction and development effects have been suggested in two species, researchers can concentrate on improving the statistical interpretation of this phenomenon by using a very large number of experimental animals. EPRI now plans to sponsor a major experiment at two different laboratories and will use hundreds of rats. This experiment may cost about \$3.5–\$4 million, on top of the roughly \$12 million EPRI has already spent on animal research.

The new rat experiment will use the same protocol as that followed with the swine, but the substantially greater numbers of animals will add to the statistical sensitivity of the work. Also, three different field strengths will be used: one that is the same as in previous experiments; one that is twice as large; and one that is lower, which will be chosen to simulate the likely upper limit of human exposure. The experiments are scheduled to begin sometime during 1985 and should take about a year to complete.

"This is a major investment on the part of the utility industry to protect public health and safety," asserts EPRI Vice President René Malès. "We've already learned a great deal giving us great confidence that electric field effects, if they exist, are very limited. However, the new research should help provide more definite answers to some very important questions. Information gathered from animal experiments can then be combined with actual exposure data to determine what risk, if any, is associated with ordinary exposure to low-level electric and magnetic fields. Until then, anecdotal suggestions of possible dangers need to be viewed with a large dose of skepticism. Current limits on public exposure to electric fields appear to be very conservative, even in light of the most recent research results." ■

Further reading

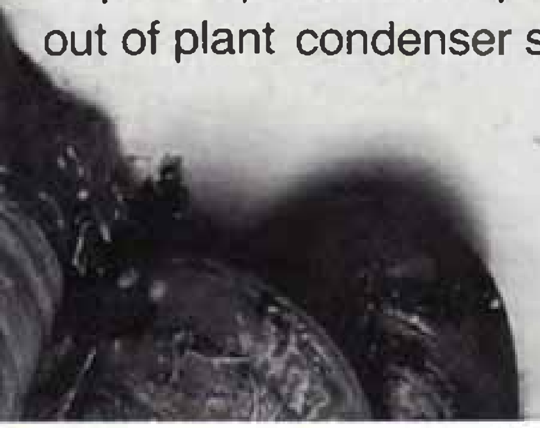
Effects of Electric Fields on Large Animals. Final report for RP799-1, prepared by Battelle, Pacific Northwest Laboratories (in preparation).

AC Field Exposure Study: Human Exposure to 60-Hz Electric Fields. Final report for RP799-16, prepared by Enertech Consultants (in preparation).

This article was written by John Douglas, science writer. Technical background information was provided by René Malès, Robert Kavet, Gordon Newell, Ralph Perhac, and Leonard Sagan, Energy Analysis and Environment Division.

Keeping Biofouling at Bay

New methods of chlorine application, alternative controls, and biofouling detection and monitoring devices will help power plant operators keep slime, algae, clams, mussels, and barnacles out of plant condenser systems—yet stay within environmental regulations.



Only a clam or a barnacle could consider a power plant cooling system home, but they do, and that's the problem. Clams, mussels, barnacles, algae, slime, and even the occasional oyster make their way into plant condenser systems with the cooling water drawn from oceans, lakes, or rivers. The shellfish lodge themselves in condenser intake conduits, and from there they are swept into condenser water boxes and tubes; the slime and algae set up housekeeping in the same warm, dark system. The result is trouble.

Power plant squatters

These squatters may be small, but they can effectively strangle power plant performance. Exhaust heat from the turbines cannot be transferred effectively through condenser tubes shrouded with slime and algae filaments; cooling water cannot flow easily through conduits encrusted with clams and mussels or condenser tubes blocked with shellfish and their debris. Power plant operators call the problem biofouling. The slime and algae, which affect about 70% of the industry's plants, are formally classified as microbiologic fouling, or microfouling; the clams, mussels, and barnacles are designated macroinvertebrate fouling, or macrofouling. Whatever you call it, biofouling is the single largest contributor to condenser downtime, and it costs the utility industry millions of dollars every year in additional fuel, lost availability, replacement power, cleanup, and repairs. For a 600-MW coal-fired plant, increases in turbine back pressure of about 0.3 inches of mercury (1.02 kPa) caused by microfouling can cost up to $500,000 a year in replacement power costs alone.

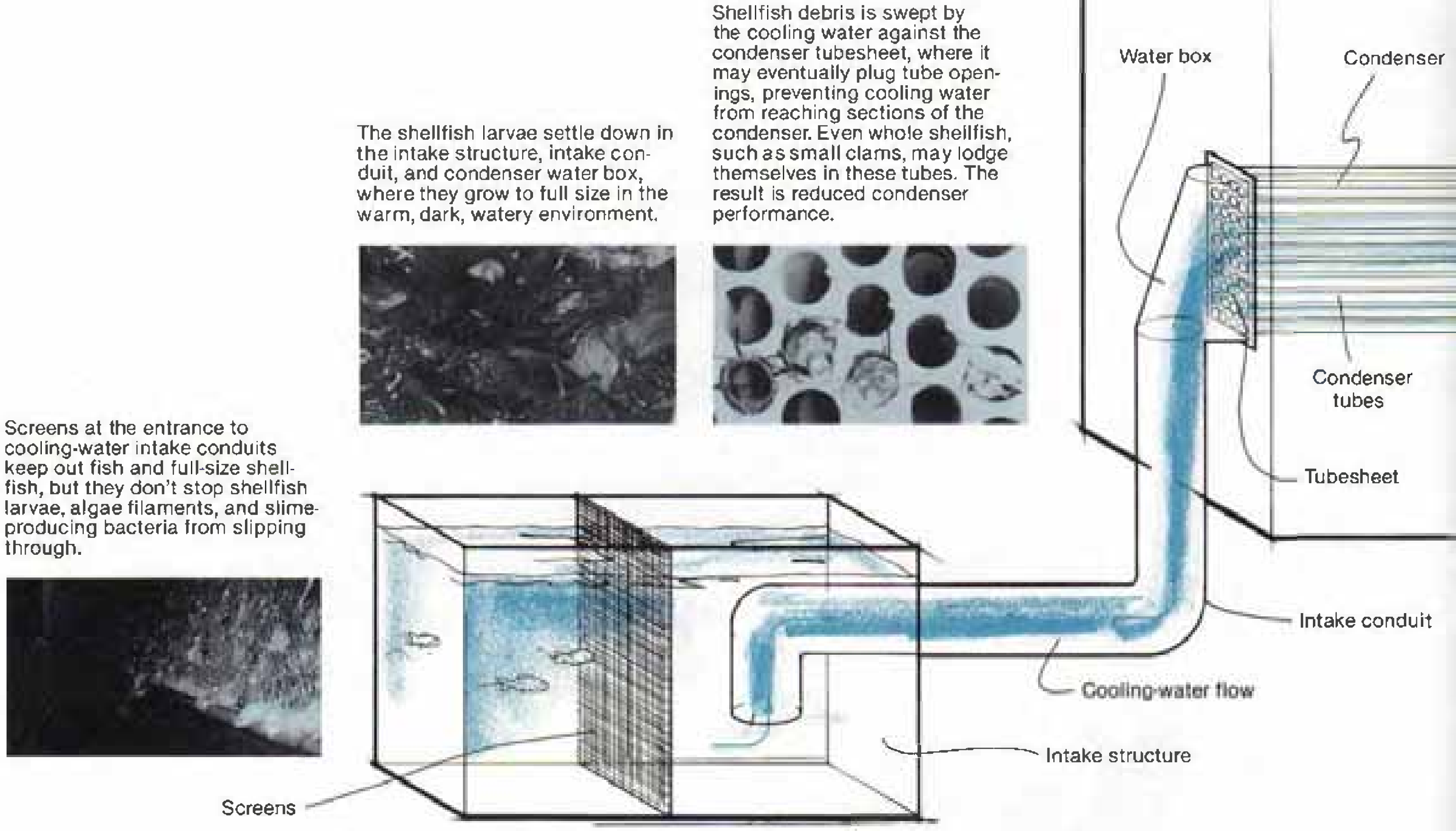
The good news is that biofouling is relatively easy to control. Chlorine flushed periodically through the condenser will quickly wither delicate slime and algae filaments, and continuous chlorination discourages the most tenacious clams, mussels, and barnacles. Chlorine is inexpensive, it works, and it is easy to apply. The chemical is simply injected into the intake conduit, and the flow of cooling water mixes it and carries it through the condenser. This combination of ease, economy, and effectiveness makes chlorination the biofouling control chosen by most power plant operators.

The bad news is that the days of uncomplicated chlorination are over. Starting in 1974 EPA issued a series of regulations under the Clean Water Act that limit the amount of leftover chlorine (residuals) that can be discharged from power plants; many states have tightened these regulations even further. Most utilities can still use chlorine to keep their condensers clean, but they have to be far more exacting about how they use it to stay within the new regulations.

That will not be easy. Although chlorine has been used for decades to keep plants clean, chlorination itself is still an imprecise art. Operators adjust chlorination dosage, duration, and frequency to meet the needs of their plants as best they can, using experience as a guide. In the past, some operators tended to use high doses of chlorine to keep their plants in top running order. "Now utilities have to cut back on chlorine. To do that and still keep plants operating at peak performance, they need a better understanding

Besieged by Biofoulers

Biofouling makes its way into plant condensers with the cooling water drawn from rivers, lakes, and oceans. This schematic shows how biofouling affects once-through cooling systems; plants with closed cooling systems can have biofouling problems, too.



than they currently have of both biofouling and chlorination," reports Winston Chow, manager of biofouling projects in EPRI's Coal Combustion Systems Division.

Chlorine is certainly not the only means available to utilities for keeping intakes and condensers clean, but no other available method of control seems to match its ease, economy, effectiveness, or familiarity. For example, alternative biocides, such as bromine chloride and ozone, cost far more than chlorine, and there are still questions about the best way to apply them, as well as uncertainties about their long-term environmental effects.

There are also on-line mechanical systems available for cleaning slime and algae out of condenser tubes. These include foam rubber balls that scrape tube walls clean as they squeeze through, and rattail brushes that scrub back and forth inside the tubes. Mechanical systems are used at a number of plants, often in conjunction with chlorination, but they, too, are costly compared with chlorine, particularly when both systems are employed. Further, mechanical systems can sometimes abrade condenser tubes when stray sand and dirt get in the way during cleaning, shortening tube life and reducing availability.

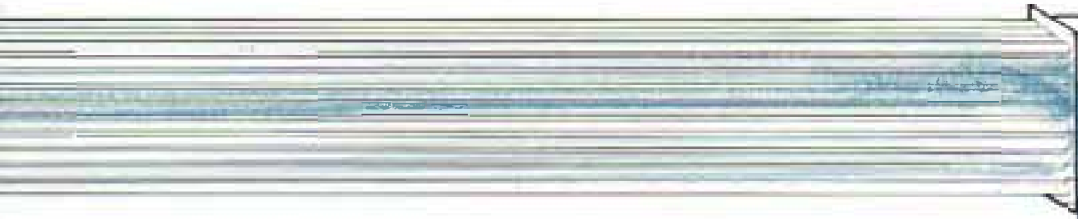
A few plants are trying heat treatment to control slime and algae in condenser tubes. By recirculating feedwater repeatedly past the hot condenser, the usual condenser water temperatures of 60–80°F (16–27°C) can be elevated to 100 or 105°F (38 or 40°C), which will eliminate most microfouling. Depending on plant design, the heated water can sometimes be discharged through intake conduits, eradicating clams and mussels there as well. Existing plants may require extensive retrofits to permit heat treatment, but new plants can be designed with this capability. A better understanding of how heat treatment works will have to be firmly established before this tactic becomes widely accepted.

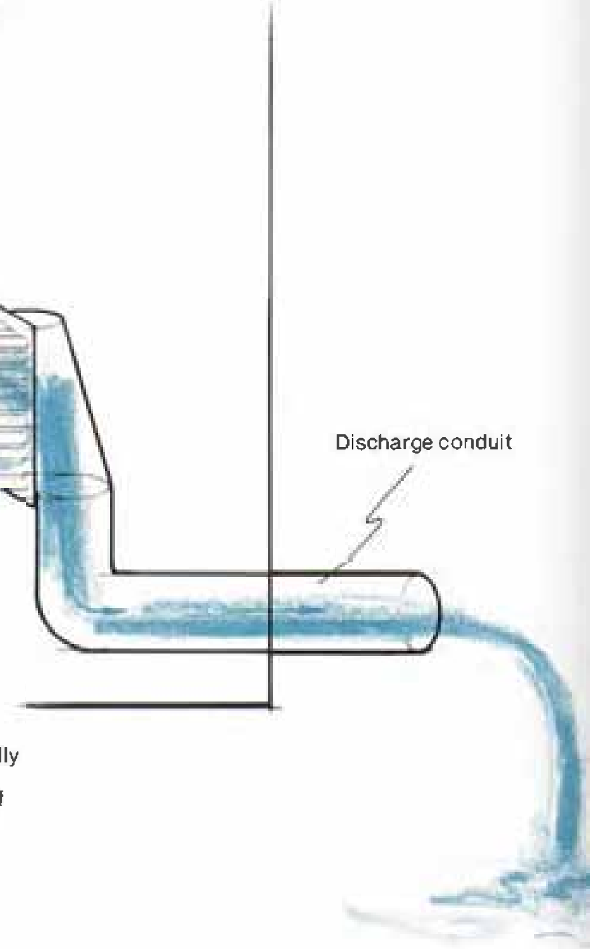
If and when to treat

Given these less-than-perfect alternatives, most power plant operators would prefer to continue to use chlorine, even at lower dosage levels. "But the trouble is, we don't have reliable, standard techniques or instruments to tell us when cleanup is necessary, how much cleaning is needed, or whether it has been suc-

Algae and slime also flourish in the condenser. Tubes and tubesheets draped with slime and algae interfere with heat transfer, degrading condenser performance even further.

One way of cutting back on chlorine is to use accurate, on-line biofouling detectors and monitors to assess when cleanup is needed, how much cleaning is needed, and whether it has been effective. A variety of detection systems are now being developed, including devices that measure heat transfer in the condenser, gages for measuring pressure drop across condenser tubes, and panels that can be pulled from intake conduits over periods of months to check on shellfish growth.





Most utilities now control biofouling by injecting chlorine solution into the intake; the flow of the cooling water mixes it and carries it through the system. Ever more stringent environmental regulations are encouraging utilities to reduce chlorination.

Another way to cut back is targeted chlorination. This sequentially treats specific segments of tubesheet and tubes with brief, concentrated bursts of chlorine, instead of flushing large volumes of chlorinated water through the entire condenser for long periods of time. Fixed nozzles, swiveling water lances, moving injection manifolds, and guide vanes are all ways to target chlorination.

cessful," comments Winston Chow.

Rising turbine back pressure is usually the first sign that biofouling is interfering with condenser performance. This is, however, only a crude indicator, and by the time back pressure registers trouble, biofouling may already be extensive. Better plant performance monitors, along with biofouling detectors and monitors, can alert operators to trouble before the situation gets out of hand.

Biofouling detectors can also help operators determine what level of treatment is required to control the problem and whether treatment has been successful. Utilities currently have limited means of collecting quantitative information on their biofouling situations: this can result in too much—or not enough—treatment. On-line, accurate, standardized methods of assessing how much cleanup is necessary would ensure that the correct level of treatment is applied; the same methods could also confirm whether or not treatment is successful.

Getting improved biofouling detection and monitoring methods to utilities was the object of a recently completed industrywide inventory of all devices now in use, commercially available, or under development. The study, by EPRI and Battelle's New England Marine Research Laboratory, examined 2 macrofouling detection systems and 17 microfouling systems. Only the macrofouling systems and one of the microfouling systems are now commercially available; most of the other devices are still under development.

The objective of each device is to detect and monitor biologic growth, but all are constructed and operated on different principles. Macrofouling detectors are generally located at or near cooling-water intakes; basically, they are simple devices that consist of a series of panels exposed to cooling water for a period of time. As months go by, individual panels are removed and inspected for biofouling. These devices are relatively inexpensive, but they seem to lack early-warning capability.

Microfouling detectors are usually located in or near the condenser tubes. Some detect biofouling films by sensing changes in heat transfer that indicate slime and algae cover the tubes' surfaces. Others measure pressure drop from one end of a tube to the other; a steep pressure drop indicates that slime and algae may be choking off water flow within the tube. Still others measure the layer of biofouling material directly, either by weighing a fouled test specimen and comparing that weight with the specimen's weight before it was fouled or by using acoustic techniques to determine the presence of a fouling film and its thickness.

Preliminary results indicate that some of the biofouling detectors and monitors tested will require further development; others are well developed, but their operating performance must be better defined before they can be entirely useful to the utility industry. EPRI plans to field-test several of the most promising methods within the next year, and Chow predicts that within a few years plant operators should have a range of commercial biofouling detection devices to choose from.

On-target treatment

Another approach is targeted chlorination, a new and effective way to use chlorine. Unlike conventional chlorination, which involves flushing large volumes of chlorinated water through the entire condenser for long periods of time, targeted chlorination would sequentially treat specific segments of the condenser tubesheet and tubes with brief, concentrated bursts of chlorine. The water thus chlorinated would combine with the larger volume of unchlorinated water flowing through the rest of the condenser, giving many of the chlorine residuals the chance to form harmless compounds. By the time the chlorine reaches the discharge outlet where residual levels are measured, the concentrations would be well within federal and state limits.

Targeted chlorination systems can be designed in a number of different ways. One approach is to install several fixed nozzles in the condenser waterbox, aiming each nozzle straight at a specific section of condenser tubesheet. A concentrated chlorine solution would be trained on selected areas of tubesheet and the condenser tubes beyond them. The combination of strong solution and direct application should be highly effective in eradicating slime and algae. Instead of fixed nozzles, a swiveling water lance could be attached to the waterbox and used to direct a stream of chlorine onto specific areas of the tubesheet.

Another targeted chlorination approach is to spray chlorine at the condenser tubesheet through a moving injection manifold. Because condenser tubesheets come in a variety of shapes, designs would vary. For example, a circular condenser tubesheet would require a rotating windshield-wiper-type manifold, such as one being developed by Tennessee Valley Authority (TVA); a rectangular tubesheet would require a manifold that moved linearly.

A series of targeted chlorination systems using each of these approaches—and a few others—is now being designed and assessed by Stone & Webster Engineering Corp. on behalf of EPRI. The study is well under way, and the advantages of each of the systems are becoming apparent. For example, the fixed-nozzle approach seems to be highly reliable: all moving parts, including valves, are located outside the waterbox and are easily accessible to maintenance personnel. The advantage of the water lance is that it can be inserted into the waterbox to inject chlorine close to the tubesheet and later pulled back during maintenance. The movable injection manifold's selling point is that it injects chlorine directly into the tubes, achieving high chlorine concentration with a short contact time.

The most promising designs will eventually be tested at one or more plants that have biofouling problems. Meanwhile, TVA has recently designed and installed its own targeted chlorination system at one of the units at the agency's Kingston, Tennessee, plant; this system, operating since July 1983, uses a rotating manifold on the plant's circular condenser. Targeted chlorination systems should be relatively inexpensive and simple to retrofit, according to Chow, and they could be widely adopted by the utility industry once the concept is fully proven and demonstrated.

If a utility still cannot maintain plant operating performance and meet chlorine discharge regulations at the same time, or if a backup alternative is desired, a final option is to dechlorinate the cooling water that is discharged back into oceans, rivers, or lakes. Dechlorination is usually accomplished by adding sulfur compounds to waste water, thereby reducing many of the chlorine residuals to harmless chlorides.

Dechlorination equipment has been installed at only a few power plants thus far; many more utilities are considering this option, but have to learn more about it. EPRI and contractor Sargent & Lundy Engineers recently completed a survey of power plant dechlorination systems, and they are preparing to publish a dechlorination manual later this year that reviews the systems and offers guidelines for engineering design and system operation. A workshop held this July in Chicago spotlighted design and operation issues that will appear in the manual.

Future alternatives

Even with regulatory limitations, chlorine remains the most popular choice for controlling biofouling and keeping plants in business. But if environmental regulations continue to tighten, alternatives to chlorine may become necessary. A number of advanced control methods are now being developed that may not be practical for the near term yet may be adopted in the future, depending on the regulatory climate.

Antifouling paints are one possible alternative for controlling both microfouling and macrofouling. These paints, which often contain copper compounds, work on the same principle as the sheets of copper that shipbuilders once riveted to their crafts' hulls to discourage barnacles. Today, antifouling paints are employed on many ships, and a few utilities are experimenting with these paints in power plants.

EPRI contractors Battelle, New England Marine Research Laboratory and Stone & Webster Engineering Corp. are now studying selected antifouling paints on test panels in intakes and intake conduits at some 20 power plants to determine how effective they are in controlling biofouling and how well they hold up under the rigors of plant life. The paints will eventually have to undergo tougher testing in plant condensers to determine if they impede heat transfer and if they can withstand the high temperatures in that area of the plant.

Further off, but still intriguing, is the possible use of ultraviolet light to kill slime and algae present in feedwater as it flows into the condenser. This approach has not yet been tried in power plants, but other industries are using ultraviolet light for similar purposes. Still another possibility is to modify conduit and condenser surfaces so that slime and algae colonies are unable to get a toehold. Calspan Corp.'s Advanced Technologies Center has recently been experimenting with surface modifications at two East Coast power plants. High-frequency ultrasonic vibrations are yet one more biofouling control alternative now under development.

Because no utility is likely to be willing to devote an entire plant to testing biofouling control concepts, EPRI is considering building a condenser test facility for just that purpose. A feasibility study is now under way to see how such a facility could be designed and what it would cost, and results are expected later in 1984, at which time EPRI will decide whether or not to build the facility.

As long as plants use cooling water from oceans, rivers, and lakes, utilities will have to work to keep slime, algae, clams, mussels, and barnacles out of condensers and intake conduits. But new biofouling detection and monitoring devices, new methods of chlorine application, and alternative controls can ensure that plants stay clean, while complying with environmental regulations. ■

This article was written by Nadine Lihach. Technical background information was provided by Winston Chow, Coal Combustion Systems Division.

EPA CHLORINE REGULATIONS

Regulations limiting the amount of chlorine allowed in water leaving a power plant are set by EPA under provisions of the Clean Water Act. Individual states may also set their own limits, but these are usually closely related to federal requirements. More than a decade has passed since EPA first proposed its regulations, and several changes have been made during this time. The result has been a complex and increasingly stringent set of requirements, the most recent of which were scheduled to take effect on July 1 of this year.

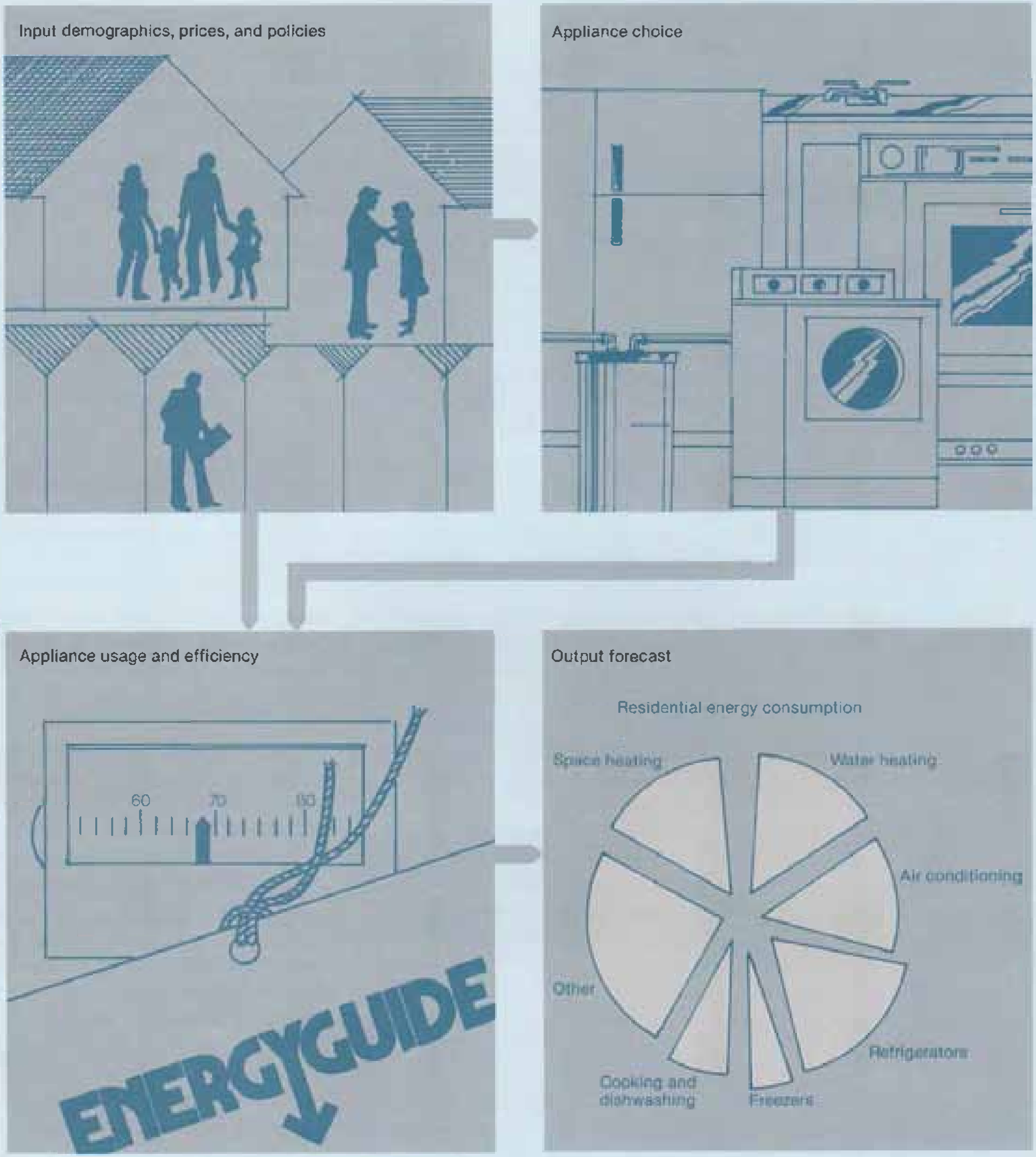
Initially, EPA required utilities to meet standards based on the best practicable control technology currently available. The deadline for complying with these regulations was July 1, 1977. By July of this year, utilities were expected to meet tougher standards, which were based on the best available technology that is economically achievable. There are two categories of the best available technology, one for once-through cooling-water systems and another for the blowdown water recycled and then discharged from cooling towers.

For once-through cooling systems at plants with more than 25-MW generating capacity, the current regulations specify that total residual chlorine is limited to a maximum concentration of 0.2 mg/L at the point of discharge. This means that many utilities will now have to make two separate measurements because effectiveness against biofouling does not depend on the total chlorine compounds present, but rather on the free available chlorine, and there is no simple correlation between the two. At plants with less than 25-MW generating capacity, operators will be able to continue controlling only the free available chlorine, with discharges limited to an average of 0.2 mg/L and a maximum of 0.5 mg/L. Nevertheless, for all once-through cooling systems, chlorine discharges are limited to two hours per generating unit per day.

Because the waste stream flow from a cooling-tower system is much less than that from a once-through system, EPA decided to use less-stringent requirements on the discharge of chlorine from these plants. Regardless of plant size, the regulations require that discharges of free available chlorine be limited to 0.2 mg/L average and 0.5 mg/L maximum, without time limit, so long as the water does not become too acid or too alkaline (a pH range from 6 to 9).

In addition to these regulations on plant discharge, the Clean Water Act also authorizes establishment of national ambient water quality criteria. On February 7, 1984, EPA proposed for comment two different classifications of these criteria as they affect chlorine and its compounds. In fresh water, the 30-day average of total residual chlorine would not be allowed to exceed 8.3 $\mu g/L$, with a maximum concentration of 14 $\mu g/L$. Concentrations between these two limits would be allowed for up to 96 hours. In salt water, the 30-day average of chlorine-produced oxidants (by-products created by chlorine reactions in salt water) would be limited to 7.4 $\mu g/L$, with a maximum of 13 $\mu g/L$. Again, concentrations between these limits would be allowed for a total of only 96 hours. If these ambient water quality standards are finally adopted, state regulatory agencies could then apply them to make plant discharge requirements even more stringent. □

The REEPS model integrates the traditional inventory approach of end-use models with the behavioral aspects of econometric models to provide forecasts of residential energy consumption under a variety of assumptions. Input variables to drive the model include housing and household demographics (e.g., household size, family income, age of head of household, building type and age, number of rooms), as well as energy prices and presumed policies and conservation programs. "What if" scenarios can be played out to help evaluate the cost-effectiveness of existing or proposed demand-side planning programs.



REEPS: Simulating Residential Response

Some 15 utilities are now using or testing the Residential End-Use Energy Planning System (REEPS) model for forecasting load and evaluating demand-side planning programs. Most are finding it takes an investment of only two or three man-months to assemble the necessary data and get the model running.

The inflation of the last two decades, the rising costs and time in power plant construction, and the oil embargo of the 1970s forced major changes in the way both utilities and their customers treated energy. Utilities could no longer count on cheap oil or gas to buffer underestimates of customer demand, while overestimates that resulted in unused generating capacity also proved costly. Consumers, too, realizing that energy was neither cheap nor in unlimited supply, became more and more sensitive to its efficient use.

Utilities and government encouraged this consumer sensitivity through a variety of demand management programs, and as a result, the relationship between utilities and end-users became increasingly close. Utilities had to know how the size and shape of their loads would be affected by demand-side programs, such as time-of-use rates or a utility rebate for installing home insulation or energy-efficient appliances.

In the last decade the number and variety of these utility-sponsored demand management programs have increased dramatically, and today electric utilities are investing millions of dollars in programs that include conservation and load management, alternative rates, and strategic load growth. Consequently, detailed and structurally articulated energy demand models are needed to forecast and evaluate the impact and cost-effectiveness of such demand-side strategies.

In the past, forecasting energy demand has been approached in two distinct ways, each with its advantages and limitations. The econometric or behavioral models used mathematical and statistical analyses that were based on economic and consumer theory to forecast consumer response to a variety of economic variables, such as energy costs, income, and utility or government policies. Although based on historical data on consumer response, econometric models tend to function as black boxes, predicting the degree of consumer response without providing a detailed picture of how that response is manifested in energy use.

In contrast, typical end-use models focus on the actual and predicted stock of energy-using equipment and its energy consumption, resulting in a detailed characterization of energy use. Total energy consumption is obtained by adding energy-use projections for individual appliances. However, because of their lack of attention to economic factors, many end-use models tend to be insensitive to customer behavior (i.e., consumer response to energy prices, incentive policies, and other factors that often are critical in determining actual energy demand). Such end-use models, for example, might not be well suited to forecasting the effect of a utility rebate for customers who purchased electric heat pumps.

Recognizing the need for an energy demand model that would provide fine detail and also be sensitive to customer behavior and response to economic variables, EPRI initiated a project in 1978 to develop a new hybrid type of residential end-use model. The behavioral aspects of the model were derived from a statistical analysis of household survey data. These data provided the detailed information on household and appliance characteristics necessary to infer the sensitivity of customers to energy prices, policies, and other economic variables. The resulting hybrid end-use–econometric model is REEPS. Recent modifications of the system have enhanced it so that it is applicable to small, arbitrarily defined regions, such as utility service areas.

REEPS gains power as an analytic and forecasting model by separating or disaggregating both the various end uses and the customer characteristics. It segregates appliances into seven end-use groups—space heating, space cooling,

Initial Users of the REEPS Model

Baltimore Gas & Electric Co.
Bonneville Power Administration
Florida Power & Light Co.
Gulf States Utilities Co.
Nevada Power Co.
New York Power Pool
New York State Electric & Gas Corp.
Niagara Mohawk Power Corp.
Northeast Utilities
Northwest Power Planning Council
San Diego Gas & Electric Co.
Sierra Pacific Power Co.
Southern California Edison Co.
Southern Company Services, Inc.
Utah Power & Light Co.

water heating, refrigeration, freezing, cooking, and dishwashing—plus a miscellaneous category. Some of these are broken down further into categories that reflect technologic differences in the way the appliances operate (e.g., electric resistance, heat pump, and standard forced-air space heating). REEPS also distinguishes between three fuel types (electricity, natural gas, and other fossil fuels) and between 29 categories of dwellings, differentiated in terms of structure, size, and age.

The disaggregation of customer characteristics is best seen by examining one of the unique features of REEPS—microsimulation. It is with this simulation of customer behavior that the information flow through the computer model begins. First, a representative sample of households in the given region or service area is generated on the basis of information drawn from surveys of consumer characteristics. Each sample household is characterized by data on socioeconomic

Electric Appliance Penetration
(% of U.S. households with electric end-use devices in November 1981)

	U.S. Total	Northeast	North Central	South	West
Main space heating	17	9	8	28	21
Central air conditioner	26	10	26	42	20
Room air conditioner	31	39	34	34	14
Water heater	33	20	25	50	27
Clothes washer	70	66	73	71	72
Clothes dryer	45	34	48	50	45
Color television	82	84	84	79	84
Oven	53	42	50	60	60
Refrigerators (two or more)	13	14	16	9	12
Freezer	38	28	46	43	32
Dishwasher	37	36	32	34	48

Source: Department of Energy, Energy Information Administration, *Housing Characteristics, 1981*, DOE/EIA-0314(81), August 1983.

attributes, such as family size, income, and the age of the head of household; number and type of appliances; size and type of dwelling; and the various geographic and economic features of the region. With this diverse and disaggregated sample established, REEPS begins to make an interdependent series of forecasts.

The first of these is a projection of appliance investment choices, which is dependent on the already established household and dwelling characteristics, weather, and energy prices. For example, a high-income family in a hot climate with low electricity prices is more likely to purchase central rather than room air conditioning than is a family living in a cooler climate where electricity prices are higher.

The second forecast predicts energy use for each household, given its appliance choices and demographic characteristics. This projection depends on the operating efficiency of the appliances and how the household chooses to use them – decisions simulated by REEPS. Total energy consumption for a household is simply the sum of the forecasts for individual appliances.

Total consumption for the region is forecast by multiplying the individual predictions for sample households by their respective sample weights in the overall region and adding the results, giving an aggregate forecast of energy demand. Thus, with microsimulation, energy use can be examined in an overall aggregate perspective or in terms of discrete market segments differentiated by income, family size, dwelling type, or other variables.

Because of the way the model is constructed (from the ground up), it offers a richly detailed picture of just what effect a price change, an advance in appliance or energy technology, or an incentive program might have. It not only predicts what the effect will be overall but also describes to whom, to what, and how that effect will apply. In short, REEPS allows utilities to predict the effect of conservation or other demand management programs on specific segments of the population, as well as allowing an overall view of a program's effect. This feature is not present in more-aggregated end-use models that deal only with an average or typical household.

The enhanced REEPS model was developed so utilities could use data from their own regions and individual demand-side programs. The Pacific Northwest Utilities Conference Committee, Baltimore Gas and Electric Co., and Florida Power & Light Co. (FP&L) each participated in demonstrations of this modified REEPS computer code.

In the case of FP&L, the utility was spending $30–$40 million annually for conservation marketing and wanted to determine whether additional expenditures on rebates for customers who installed energy-efficient appliances, solar water heaters, heat pumps, or attic insulation would lead to significantly greater energy savings. Because it brings together both end-use detail and customer behavioral patterns, REEPS enabled the utility, for the first time, to determine if the existing program was cost-effective. REEPS showed, in fact, that the rebate program was already operating at nearly optimal effectiveness, and FP&L made the decision not to invest a further $3–$4 million per year over the next five years.

In addition to the three demonstration utilities for REEPS, 12 early user utilities have signed prerelease licenses for the REEPS software and are testing the model with their own data. A production version of the REEPS code will be available this year.

For utilities that have not yet instituted demand-side programs, REEPS provides a powerful analytic tool for evaluating various programs under consideration and accurately targeting program expenditures. The utility industry as a whole can now benefit from an inclusive, finely articulated disaggregate residential load-forecasting model that will help integrate load forecasts with demand-side program planning. ■

This article was written by Stephen Tracy, science writer. Technical background information was provided by Steven Braithwait, Energy Analysis and Environment Division.

The French Nuclear Experience

The nuclear attaché for the Embassy of France discusses the French energy program, emphasizing that country's commitment to standardized plants.

Bertrand Barré, nuclear attaché at the French Embassy in Washington, D.C., joined the French Atomic Energy Commission in 1967. With a background in nuclear engineering, Barré has worked extensively with materials and reactor design. He spent two years in Great Britain collaborating on the Dragon project and a year in San Diego working on high-temperature reactors. In 1976 Barré became technical adviser to Michael Pecqueur, deputy chairman of the French Atomic Energy Commission; when Pecqueur became chairman of the commission in 1978, Barré remained as his technical adviser. Barré joined the embassy in Washington in September 1980.

What role do you play at the embassy as nuclear attaché?

As nuclear attaché I wear four different hats. I am an adviser to the ambassador, and as such, I work mainly on nonproliferation as a liaison to the U.S. State Department. I am the representative of the French nuclear industry in this country; in this capacity, I serve as liaison to the Department of Energy and the Nuclear Regulatory Commission. I am also here as an observer, and I report back to France on the nuclear scene in this country. My fourth role is as spokesman for the French government and industry as far as nuclear energy is concerned. From time to time I speak at universities or attend meetings, and I supply all the information available on the French nuclear program to anyone who asks.

What is the current energy situation in France?

To answer that question I would have to go back and start with the situation as it was in 1973. At that time we were using oil for about 68% of our total energy balance, and 98% of this oil was imported. We also imported about half of our coal and two-thirds of our natural gas. We had a sizable hydroelectric program, but most of the sites were equipped or in the process of being equipped. There was little potential for increased energy from hydroelectric power.

The French nuclear program was still embryonic in 1973. France started its atomic energy program rather early—the Atomic Energy Commission was established in 1945. In 1946 all the utilities of the country were united and nationalized to form one big utility, Electricité de France [EDF]. EDF covers the whole country and has a monopoly on distribution and transmission; it produces 80% of all electric generation in France. By 1973 EDF had achieved a very extensive program of engineering in hydroelectric projects, so there were teams of engineers in-house who were quite competent in managing big projects. This was an important factor in the development of nuclear energy.

Before the first OPEC meeting in 1971, oil was $1.70 a barrel; by 1975 it was $13 a barrel. It was suddenly obvious that our dependence on oil was simply unbearable. We had become much too vulnerable, particularly to cutoffs, and we couldn't afford the new price of oil without severe strain on the nation's economy.

What options did the French government have at that time?

To reduce oil imports, we had three choices. First, we could boost domestic oil production, which is what you did in this country. However, this was not really an option for us. Our reserves are ridiculously low. We were producing all that we could, and that wasn't very much.

Our second choice was, of course, to conserve oil. Energy became much more expensive almost overnight, so there was a big incentive to conserve. We were, however, already quite thrifty as far as energy consumption was concerned because France has a historical record of high energy prices. At that time, we were consuming energy at a level of 3.5 tons of oil equivalent per capita a year. To give you an idea of what this means, Americans were consuming at a rate of 8.5 tons of oil equivalent per capita. So in France there was much less fat to be trimmed. There was a limit to what we could achieve without going from conservation to starvation.

Our third policy option was to switch fuel, but this brings us back to the original problem. Boosting domestic coal production was technologically possible, but economically very difficult. Coal from Australia, coming in through French ports, was still cheaper than French coal. We did, however, manage to diversify a bit by importing coal from countries other than those from which we were importing oil. We were importing two-thirds of our natural gas, and our main supplier, the Netherlands, indicated that it would be decreasing rather than increasing exports because its resources were dwindling. Our hydro program, as I said, offered little potential for increase, and renewables, though a long-term prospect, have long lead times before they can offer any significant input. On the other hand, we had the background and experience to launch a crash program in nuclear energy, and this is what we did. At the end of 1974 the government decided to increase roughly four times the pace of the nuclear construction program that was already under way.

How successful was this accelerated program in nuclear energy?

In 1973 nuclear energy accounted for less than 2% of France's primary energy consumption; it has now reached 17%. Oil, which was at 69% in 1973, has been reduced to 47% of total energy consumption—a decrease we hope to push to less than 30% by 1990. At that time use of nuclear energy will be on a par with oil. In terms of electricity production, nuclear was supplying only 8% in 1973, while oil was supplying 75%. To show you that our crash program didn't achieve results quickly, in 1977 nuclear still accounted for only 8.4% of electric generation. In 1983, however, nuclear accounted for 48% of electric generation, and this year it will produce more than 55%. There is a high likelihood that by 1990, we will have reached our goal to make the nation's electric grid invulnerable to cutoffs from any foreign supplier.

The rate of our increased use of nuclear power has been unique, even if you look at other countries with the same incentives for nuclear power that we had, such as Italy and Japan. In 1976 France ranked eighth in terms of nuclear energy production; in 1983 we ranked second behind the United States, although the United States is geographically much larger. We have outdistanced Japan and the Soviet Union; we produced twice as much nuclear energy as Germany and three times more than Great Britain. France's program is a unique phenomenon worldwide.

How do you explain this unique success?

There is no single reason, but rather a convergence of reasons. First, the incentive was there. We were heavily dependent on foreign oil, and there seemed a national will to do something about that dependence. France also experienced an oil embargo in 1956, after the Suez expedition, so maybe there were still nagging reminders that we were vulnerable, which added a psychological pressure to the situation.

Second, we had a single utility that was able to be its own architect-engineer and to manage projects of this large scope. At that time the nuclear industry was still rather limited; we had only eight reactors in operation, the largest only 550 MW, but we did have the experience. Also, in 1973 we had complete mastery of the fuel cycle—we even had a breeder reactor in operation. The Phénix plant had become critical in the spring of 1973. The AEC had considerable experience in all areas of nuclear energy. So there was a sound infrastructure ready to go.

The third important step was that instead of shopping around, we decided to focus on one kind of reactor—the pressurized water reactor (PWR)—built by one supplier, Framatome, which has a license from Westinghouse Electric Corp. We decided to order a number of identical 900-MW units and to increase the size to 1300 MW later on. Currently, there are twenty-seven 900-MW reactors in operation and 7 under construction. The first 1300-MW reactor should go critical very soon, and there are 19 others under construction. We are just now ordering the next batch of units, which will be slightly over 1400 MW. The policy of ordering by batch of identical units was probably the main reason for our success.

What are the benefits of such standardization?

The policy of ordering identical units has a number of attractive features; it also has some drawbacks that I will discuss as well. By its large orders, EDF enabled Framatome to build brand new facilities, knowing that it would have a reasonable number of orders for many years. This gave Framatome a total manufacturing capacity of eight 900-MW units a year or five 1300-MW units, which was consistent with the rate of ordering six domestic units a year and two for export. Also, by being such a big customer, EDF could control prices quite strictly. In addition, there is only one French supplier of turbogenerators, Alsthom-Atlantique. The same factors apply here as well—Alsthom-Atlantique could modernize equipment, and EDF could control price.

As far as plant construction was concerned, EDF already had a special division in operation for all the engineering and management aspects of the program. Its staff applied the same competence and dynamism to the nuclear program as they had applied to the hydro program. The first 900-MW unit, Fessenheim I, took 80 months to build; the average time now for a unit of this size is only 60 months—just five years—which is not much time for a project of this size. Standardizing our nuclear program also made the licensing process much easier. Once the original plant had been licensed, the licensing process could focus attention on site characteristics and minor departures from the standard design at each subsequent plant. This made it much easier for the licensing commission to deliver on time. I hear many complaints about the U.S. Nuclear Regulatory Commission, but I tend to sympathize with the problem of having to license 78 different reactors. Up to now, there have not been two identical units anywhere in the United States, and this does create licensing problems.

By standardizing our program we also minimized training problems for nuclear personnel. In France, personnel can be switched from one plant to another, and they will find the same control room and the same procedures. In case of emergencies, this is very valuable. If one plant is in trouble, we can run simulations in a number of other plants, and we can send experienced engineers from one plant to another. Having only one supplier and a strong utility able to control prices has made nuclear energy in France by far the cheapest way to generate baseload electricity. It is 50% cheaper than coal and three times cheaper than oil.

There is, of course, a negative side to ordering a number of identical units. We make ourselves vulnerable to a common-mode failure. If one large failure occurs, 30 units would be affected. That was the initial gamble. By now we know for sure that these plants can operate at least six years without serious problems. So we are not as vulnerable as it initially appeared. We did, in fact, experience one of these common-mode problems. It followed the pattern of developing in our oldest plant and spreading to other plants. We were able, however, to take preventative action on those remaining plants at each of the refueling and maintenance outages that followed. If we experience any such problem in the future, we will have sufficient advance warning to take preventative measures in other plants and sufficient backup plants to ensure reliable service.

What about public sentiment on nuclear power?

There has always been majority support here for the nuclear option because it was consistently presented by the different governments over the years as the best option to reduce our dependence on foreign oil. This part of the message was always clear. There also has always been a strong minority opposing nuclear power. In October of 1983, however, a survey carried out in all 10 countries of the European community showed that support for nuclear power is strongest in those countries, like France, with the biggest nuclear programs. The fear of nuclear power is also lowest in those same countries. This evidence is somewhat hard to interpret—it's a chicken-and-egg situation. Has nuclear power developed in countries that fear it less or because people accustomed to seeing nuclear plants fear them less? I'm not sure which is true, but the results of the survey are still a fact. The same survey was taken two years before, and comparisons show that support has grown and fear decreased over those two years.

The current trend in France is growing support of nuclear energy. A related survey showed the French people still thought there might be an energy crisis looming in the future. There you have the main basis for support of nuclear power—not all people like it, but most think nuclear energy is better than an energy crisis.

As far as organized opposition is concerned, there is a major difference between protests in France and in this country. In France the protest concerned additions to the nuclear program; the opposition has never asked for shutting down existing plants or even for stopping construction on plants already under way. There was protest over opening new sites, and even today the opening of new sites is always a hard process. However, putting a new plant in the same site is not a big problem. Once a site is opened and the plant in operation, there is very little protest. A striking example of this is the Superphénix breeder reactor, which was the focus of strong protest. Opposition went far beyond the French borders; it was really European opposition. Since 1977, however, there hasn't been one sig-

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nificant protest at the site. The plant should go critical in 1985, and there have been no more problems with public acceptance. La Hague, our reprocessing plant, is still the stage for some protests. However, the massive protests involving local opposition have died down; what we have now I would call professional protesters.

What are the licensing and regulatory processes in France?

The licensing processes in France are very close to those in the States with one basic departure. Contrary to what you may have read from time to time, we do not have one-step licensing; this is a misconception. What we do have is only one step of public participation at the very early stage of site approval. Once the site has been authorized, there is no longer the possibility of public participation. There is always the possibility of going to court, but otherwise, the public is no longer part of the actual process.

The actual licensing process is carried out in exactly the same way as in the United States, but within the licensing body. The licensing body is part of the executive branch and reports directly to the Minister of Industry and Research. In the United States, utilities have to issue a preliminary safety report, apply for a construction permit, show a final safety report, and receive an operating license. The process is exactly the same in France. One of the differences, of course, is that it is easier to make the safety report if you are licensing a plant that is identical to all the other plants. This speeds up the licensing process, as well as any subsequent retrofit that might be required.

As far as the regulatory aspects are concerned, there is a much less antagonistic relationship between the utility and the regulators than exists in this country. For example, for those retrofits considered necessary but not urgent, the regulatory body has authorized the utility to wait until the next planned outage rather than ordering shutdowns.

What is the current status of your breeder program?

France began breeder studies in 1953, and our first reactor, Rapsodie, was in operation in 1967. Originally a 24-MW (th) reactor and later boosted to 40 MW, Rapsodie was a test reactor; we used it to develop fuel for other reactors and for a number of other studies. It was shut down last year, having outlived its usefulness. The second step, and one of the most successful, was the Phénix plant, a 250-MW (e) plant that went critical in July 1973. Phénix was built in five years and within budget—quite an achievement. It incorporates all the basic features of French design: liquid sodium cooling, mixed oxide fuel, and a pool-type design. With the pool-type design, inside the pool you have not only the core but also the primary system, together with its components, pumps, and heat exchangers.

The Phénix reactor was proof of the system. It has been operating very well since 1973 and has generated over 12.5 billion [10^9] kWh. For a reactor this size, it has a load factor comparable to most routine PWRs and BWRs. In addition, we have had some very interesting incidents concerning the Phénix, which were to be expected as part of its experimental nature. These incidents involved the primary heat exchanger and steam generators and at times provoked down periods of up to a year. These are significant periods, but we have gained a lot of confidence in the system because we found that we could master such incidents without lasting consequences.

One of the things that amazes most people is that sodium is so completely noncorrosive. You can remove equipment that has been operating near the core for five years, and it looks brand new. It is also easy to decontaminate. After washing away the sodium, you can put your hand on the primary heat exchanger, and the radiation level is only about 100 mr/h. This is quite an important statistic if you want to replace a generator. Radiation dosages to maintenance and operating crews are amazingly low, more than one order of magnitude below the doses of operating a standard water reactor. So, even from an operational point of view, it is a reactor that the nuclear personnel like. But it is expensive.

The Phénix was not of commercial size, so the next step is Superphénix, which has been built at Creys-Malville. Initial testing of this new facility is already under way, and because it is a one-of-a-kind operation, these tests will be rather extensive. Superphénix is a multinational venture: it is owned by a company called Nersa, 51% of which is owned by EDF, 33% by the national utility of Italy, and 16% by SKB, which is mostly German. Superphénix is 1200 MW (e), and we hope it will be the proof of complete technical feasibility for a commercial breeder. It will not be proof of commercial feasibility because it, too, will be expensive. Electricity generated by Superphénix will be about twice the cost of electricity generated by traditional PWRs. So it might be more expensive than coal, although it will certainly be less expensive than oil.

Just recently, you may have read, there have been a number of agreements among European countries concerning breeder reactors. In particular, there has been a special agreement between EDF and the Central Electricity Generating Board, so the British are now part of this European operation. It is anticipated that the British will have an ownership in Superphénix II, or whatever it is called at the time it is available for orders. This will not take place until after one year of successful Superphénix I operation to make sure that none of the options we took were problems.

Your breeder program is in keeping with your general philosophy of controlling the fuel cycle, correct?

Yes, controlling the fuel cycle is a very important part of the story. In the United States antinuclear forces sometimes have a very easy argument that although you are building reactors, the fuel cycle is not following at the same pace. This is not so true in France.

In France we switched to LWRs only when we were sure that we were mastering the enrichment because we didn't want to be dependent on anyone for a vital part of the fuel cycle. About half of our uranium is mined in France. Our resources amount to about 120,000 tons, and probable reserves amount to about 200,000 tons. This is not big compared with American reserves, but it is very big by European standards. These resources give us long-term security; we can always increase production in time of need. On a routine basis, we rely on imports for the other half of our uranium needs, mostly from Africa. However, our full mining capacity in France means that we could afford a cutoff of all uranium imports for 10 years with no adverse effect on power.

We started with a gas-cooled reactor, as did the British. With this type of reactor, the spent fuel cannot be stored in pools for very long. Reprocessing was not optional. We had to reprocess the fuel once it was unloaded from the reactor. So, before we even embarked on LWRs, we already had sizable experience with reprocessing. We are now expanding the reprocessing plant at La Hague to a capacity of 1600 tons per year by 1990. Some of this capacity, which is far beyond our needs, will be contracted to provide reprocessing service to 33 utilities in seven countries. Ultimately, such a capacity will be able to accommodate the full French program for quite a time. This reflects the coherence of our policy; we have not let this part of the fuel cycle fall behind.

Also, we have been able to partly answer the most nagging question that nuclear developers ask, what do we do with the waste? We reprocess to recover what is useful, and we vitrify the actual waste. The optimal timeframe to reprocess is about four years after the shutdown of the reactor, and the optimal timeframe to vitrify is about seven years after shutdown. We have had a vitrification plant in operation at Marcoule since June 1978, and it has been very successful. We are building two similar units at La Hague; the first should be in operation by 1986 to begin vitrifying the backlog there. The capacity of these two new vitrifying units will be able to accommodate the output of the reprocessing plant with a sizable safety margin.

We have begun some preliminary geologic screening for permanent underground disposal areas, but we have not made any serious decisions in this area. So, what we do not have yet is the last stage, a disposal site for high-level nuclear waste. However, there is no big hurry to find a site. Once you vitrify, very little can happen to the waste.

What is the current focus of research and design in the French nuclear industry?

One thing that we have worked on is the Thermos reactor. Thermos was an attempt to use nuclear power in an area besides electric generation; it was specifically designed for district heating. At present, although we have made a completely detailed design, we have not found a customer. It is only marginally economical. In France there is only one district heating system; that is in Paris. However, the Paris system uses dry steam, while the Thermos reactor generates hot water. To make Thermos economical, we would have to finance the reactors and also find an appropriate district heating network. This hasn't been possible up to now, but the Thermos is on the shelf and we'll have it when we need it.

More active studies currently involve small- and medium-size PWRs with a view to possible export to less-developed countries. But it is fair to say that the main thrust of our research and development is in two main areas: the breeder program and improving the large PWRs.

Having observed the nuclear industry in this country, what advice would you offer to improve our nuclear options for the present and the future?

It is difficult to advise on such an issue. Some of the things that have been beneficial in France are really not relevant in the United States. For instance, you couldn't have only one utility; the United States is far too big for that. However, having 3000 utilities doesn't help the situation.

You do not need 80 different types of reactors. The trend is to standardize; and I can only add my support for this trend. Standardization makes it much easier for licensing plants and helps to cut costs. Maybe the United States is big enough to have more than one reactor design, but certainly not more than one per vendor. The tendency of utilities to shop around and bid for the least price is probably not the best way to achieve reliability in the nuclear industry. I also think that the United States should have sites authorized in advance, before utilities start spending dollars on construction. The notion of a site bank is very good. That is what EDF does; we have sites ready today and until the end of 1987. The United States does need some licensing reform and I believe that we will see this reform take place in the near future. ■

This interview was conducted by freelance writer Mark Reynolds.

High-Sulfur Test Center to Be Sited in New York

The new EPRI test facility will evaluate environmental control options for utilities that burn high-sulfur coal.

New York State Electric & Gas Corp.'s new Somerset generating station has been selected as the site for an $11 million advanced high-sulfur test center. When construction of the test center is completed in 1986, a 10-year, $26 million research program will be conducted to improve methods of removing SO_2 from the flue gas of plants firing high-sulfur, eastern coal. Somerset, a 625-MW plant due to generate electricity later this year, is located 30 mi (48 km) northeast of Niagara Falls.

"The high-sulfur center will test new concepts that promise to improve flue gas desulfurization [FGD] technologies," explains EPRI Project Manager Charles Dene. "Any success in making current technology more reliable and efficient could result in substantial savings," he adds.

Current EPRI projects in high-sulfur flue gas cleanup require testing at sizes that range from bench scale to pilot plant. "The equipment to do that doesn't exist at one site," comments Dene. "At Somerset, we will have it under one roof, so we will be able to consolidate several research programs." He estimates that EPRI will be able to save as much as $1 million a year in research costs by avoiding equipment duplication.

The center will have a pilot-scale FGD train, a minipilot-scale FGD train, equipment for bench-scale process chemistry experiments, and gas-sampling equipment to obtain representative flue gas from the host utility boiler. Both the pilot- and minipilot-scale FGD trains will be capable of 95% SO_2 removal at inlet SO_2 concentrations up to 4000 parts per million.

NYSEG, the host utility for the center, will contribute $4.3 million in money and services to the project. ■

EPRI Studies Better Ways to Store Spent Fuel

The U.S. Nuclear Waste Policy Act of 1982 provides for the permanent disposal of spent nuclear fuel. However, because facilities for this final disposal are not yet in place, nuclear utilities face the problem of interim storage. In response, EPRI is pursuing a $7.2 million research program to help electric utilities find better ways to store their spent nuclear fuel safely and inexpensively.

Shifts in government policy over the past decade regarding treatment of spent fuel have resulted in uncertainty in the industry. The Ford and Carter administrations banned the reprocessing of spent fuel—that is, the separation of the radioactive waste products from unused uranium and plutonium that can be reused as nuclear fuel. Therefore, for the present, utilities operating nuclear power plants must store spent fuel in the form it is discharged from the reactor, although storing fuel bundles requires 16 times more volume than does separated waste. This is the incentive for research to find ways to store spent fuel more compactly and efficiently.

The broad-range EPRI research effort includes projects aimed at demonstrating new methods of storing the spent fuel, using either water or air for cooling. Ten contractors are each carrying out a project with EPRI financing, and three utilities are contributing partial funding on three projects. The cost of the individual projects ranges from $60,000 to as high as $3.3 million.

Storage of fuel in water-filled pools built for the purpose has been the prevailing storage mode until now. The EPRI research on water cooling involves the fuel rod consolidation technique—disassembling the fuel rod assemblies and packing them more tightly within containers. The goal is to be able to store the rods from two complete assemblies within the space that would be occupied by one original, uncompacted assembly. In addition, there are two demonstrations of storage that uses air as the cooling medium; one project uses metal casks and one uses concrete silos for storing the fuel.

The remaining projects, aimed at developing support technology, include an analysis of the risks of dry-storage systems, a study of the effects of oxidation on spent fuel in air, surveillance of spent fuel kept in wet storage, cost comparisons for on-site storage options, development of computer modeling techniques for heat flow and heat balance (in both air-cask storage and water pool storage), and development of modeling techniques for cladding failure.

Under way since May 1981, the program is scheduled for completion in 1987. ■

DC Circuit Breakers Pass Test

Researchers from EPRI and Bonneville Power Administration recently completed successful testing of the world's first prototype high-voltage direct-current circuit breakers. This event will significantly affect electric transmission practice in the future, demonstrating that operation of long-distance, multiterminal HVDC lines or networks is feasible. Breakers similar to the prototypes can be used on major dc transmission systems planned for operation between 1988 and 1990.

Two prototypes, one developed by Brown Boveri Corp. of Switzerland and the other by Westinghouse Electric Corp., were able to interrupt the flow of power on a high-capacity ±400-kV dc transmission line. The test culminated a three-year project (RP1507) by EPRI and BPA, with help from the Department of Energy, Southern California Edison Co., and the Los Angeles Department of Water & Power.

The two 25-ft (7.6-m) HVDC breakers, installed outdoors at the Celilo terminal on the HVDC Pacific Intertie, were tested on a fully energized, 846-mi (1360-km) dc line running from The Dalles, Oregon, to Los Angeles. They were tested at full voltage with current-interrupting capability up to 1200 A (Westinghouse) and 2000 A (Brown Boveri). The maximum voltage across the breaker terminals was limited to 700 kV by zinc oxide surge suppressors.

During a 30-hour period in February, the circuit breakers were tested for line dropping, parallel line switching, and short-circuiting at various points. In addition, the intertie was temporarily reconfigured to operate as a three-terminal network for switching tests. Both prototypes performed as predicted.

Because of their modular design, the HVDC breakers can be easily adapted to different systems, giving them great versatility. Because they can be constructed from relatively standard off-the-shelf components, such as ac breakers, capacitors, and zinc oxide surge suppressors, commercial application is ensured. ■

Booklet Geared to Distribution Utilities

EPRI's Research Applications Program recently published the *Distribution Utility Catalog*, which highlights products developed through EPRI's R&D. The 12-page brochure describes hardware, software, and other information packages resulting from the Institute's distribution and transmission programs that bear directly on distribution utility operations.

Most of the products featured in the catalog are commercially available and ready for application. A few others will be available within two years and are also discussed. Each product description is designed to convey information quickly and concisely so that busy utility staffs can easily determine which items they wish to investigate further.

The first edition of the catalog presents only a small portion of EPRI-developed products available to utilities. Later editions will highlight other areas of particular interest to distribution utilities, such as conservation and end-use technologies, demand-side planning tools, and small modular generation systems. Periodic updates will alert users to new developments.

Copies of the catalog may be ordered through the Research Applications Program, (415) 855-2716. ■

CALENDAR

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

AUGUST

13–14
Effect of Voltage Change on Energy Consumption
Dallas–Fort Worth, Texas
Contact: Herbert Songster (415) 855-2281

21–22
Seminar: Generator Modeling
Cincinnati, Ohio
Contact: Dharmendra Sharma (415) 855-2302

23
Torsional Fatigue Crack Growth in Large Turbine Generator Shafts
Cincinnati, Ohio
Contact: Dharmendra Sharma (415) 855-2302

27
5th Symposium on Transfer and Use of Particulate Control Technology
Kansas City, Missouri
Contact: Ralph Altman (415) 855-5327

SEPTEMBER

11–13
Mutual Design of Transmission Lines and Railroads
Atlanta, Georgia
Contact: John Dunlap (415) 855-2305

12–14
Life Assessment and Improvement of Rotors for Fossil Fuel Turbines
Raleigh, North Carolina
Contact: Ramaswamy Viswanathan (415) 855-2450

20–21
BENCHMARK: A Chronological Generation Simulator
Boston, Massachusetts
Contact: Jerome Delson (415) 855-2619

26–28
Symposium: Demand-Side Management
New Orleans, Louisiana
Contact: Ahmad Faruqui (415) 855-2630

26–28
Workshop: Analysis of Plant Performance and Safety
New Orleans, Louisiana
Contact: Murthy Divakaruni (415) 855-2409 (nuclear plants) or Frank Wong (415) 855-8969 (fossil plants)

OCTOBER

8–10
BWR Corrosion, Chemistry, and Radiation Control
Palo Alto, California
Contact: Christopher Wood (415) 855-2379

10–12
Seminar: FGD Chemistry and Analytical Methods
Atlanta, Georgia
Contact: Dorothy Stewart (415) 855-2609

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

15–18
Seminar: 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

NOVEMBER

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

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

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

R&D Status Report
ADVANCED POWER SYSTEMS DIVISION

Dwain Spencer, Vice President

DEMONSTRATION: COORDINATED CONTROL OF A FUEL GAS SATURATOR

Future commercial coal gasification power plants will integrate different processes and equipment. For example, a fuel gas process with gasification reactors and cleanup columns may be integrated with a combined-cycle plant of gas and steam turbines and heat recovery steam generators (AP-3486). Effective operation of integrated plants will require well-coordinated control to mitigate undesirable unit interaction. When many processes occur simultaneously, coordination becomes more difficult, especially with the single input–single output format of older conventional control equipment, which is better suited to sequential control. However, recent control system developments (i.e., hardware, software, and control theory itself) offer practical schemes for coordinated, parallel control based on a multiinput-multioutput format. One study applied such multivariable control schemes experimentally to a fuel gas saturator in a gas cleanup test facility associated with a small coal gasification pilot plant (RP2389). This control analysis, conducted on a moderate scale in a meaningful setting, illustrates the strengths and weaknesses of current coordinated control methods.

The project team selected the fuel gas saturator unit for control analysis and experimental testing because of its important role in the fuel gas production process in an integrated gasification–combined-cycle (GCC) plant, such as the 100-MW Cool Water GCC demonstration power plant (RP1459). In this configuration the fuel gas passes through the saturator unit before entering the gas turbine combustor. Mass and energy exchange connect this unit closely to other parts of the fuel gas process. The unit effectively increases the clean fuel gas temperature, while simultaneously adding water vapor to control the formation of nitrogen oxides (NO_x) in the gas turbine combustor downstream. The increased mass flow of gas from the saturator to the gas turbine also improves turbine efficiency. Therefore, to maintain a high performance level and to avoid propagating disturbances, plant operators must precisely control the saturator unit fuel gas outlet temperature despite varying input energy and flow conditions.

Test facility

This project was planned in conjunction with operation of a fuel gas process evaluation facility (PEF) by General Electric Co. under a DOE contract. Figure 1 illustrates the PEF's saturator system flowsheet. As raw gas from a fixed-bed gasifier and quench vessel cools in condenser 1 from ~338 to 296°F (~170 to 145°C), water, oils, phenols, and tars simultaneously condense and separate from the raw gas. The fuel gas proceeds to another condenser (2), where it cools further to 180°F (82°C) before entering a Benfield chemical absorption column (5) for selective hydrogen sulfide (H_2S) removal.

After leaving the Benfield absorber, the clean gas is scrubbed of any remaining alkali solvent in a wash column (6). The gas is then heated with condensing steam in a heat ex-

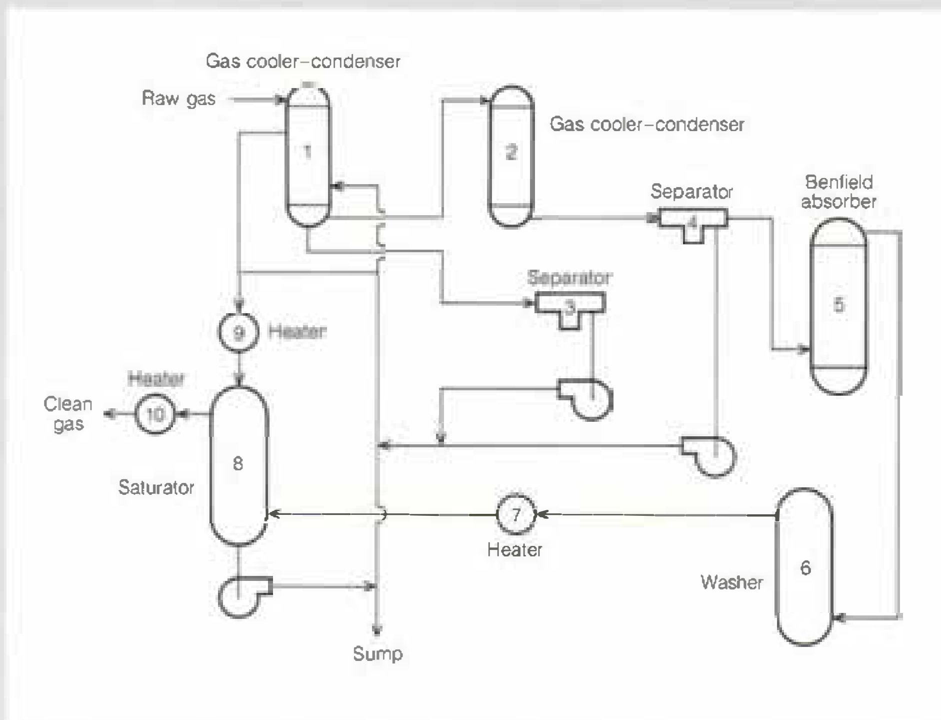


Figure 1 Experimental transient tests were conducted at the fuel gas process evaluation facility to assess alternative strategies for coordinated control of the saturator unit.

changer (7), before entering the saturator tower (8). The gas flows upward through the packed tower in direct contact with a cascading stream of recirculating liquor. This intimate contact heats the gas, saturates it with water vapor, and vaporizes some oils and phenols as well.

The condensate from the first condenser passes to a separator (3), where tars, which are heavier than water, are removed. The condensate, containing oils and phenols, is returned to the fuel gas via the saturator. These remaining organic compounds increase the gas heating value, and the water increases mass flow. The gas proceeds downstream to a system that mechanically emulates a gas turbine combustor.

In a commercial plant, the heat source for the saturator would be from heat exchange in the raw gas cooling train downstream of the gasifier. In the PEF, liquid is recycled from the saturator through condenser 1 instead of a gas cooler. Alternatively, the first condenser can be bypassed and a steam heater (9) used as a thermal energy source for the PEF saturator.

When it leaves the saturator, the gas is superheated in a steam heater (10), as in commercial practice, to prevent condensation of water droplets in the pipe to the gas turbine combustor. Liquor from the saturator sump mixes with flow from separators (3) and (4); the combined flow is heated (9) and then recycled to the saturator.

Investigators designed two computerized systems to control the saturator's different operating modes: with the first condenser and without it. In the first series of experimental tests, the PEF was operated in the latter mode with the saturator as well as the sump and the steam heaters under computer control. In a second series of experimental tests, the PEF was operated in the former mode with the first condenser, and the alternative control algorithms were applied.

The principal control objective for the saturator is to regulate the moisture content of the clean fuel gas stream to meet requirements for both NO_x emissions control and gas turbine efficiency. A secondary objective is to inhibit the introduction of water droplets in the gas turbine combustor nozzles. An increase in the temperature difference between the inlet liquid and exit gas can cause supersaturation or fogging, which the superheater may not correct. Therefore, the temperature difference is regulated to a constant value. Simulation has shown this regulation is consistent with maintaining a constant ratio of liquid-to-gas flow rates and promoting uniform temperature profiles in the saturator.

Coordinated control design

Two general multivariable feedback methods are available for designing coordinated control systems. One is a time-domain approach, which applies global process models (i.e., those with a state-space concept) and optimizes a quadratic performance index. The other method applies local process models (i.e., those with an input-output concept) in a frequency-domain method using classical notions of gain, phase, and bandwidth.

This study evaluated both methods to provide the best possible design and to determine the relative effectiveness of each method. Both approaches were greatly enhanced by on-line access to computerized graphics displays on interactive terminals. In general, this allows many design iterations to be carried out in very short time. The time-domain methods were applied by using LIMCON software; the frequency-domain methods applied CLADP software. Both methods require nonlinear models of the type that General Electric had adapted for this study by linearizing them. The linear models were then used with computer-aided control system design methods to generate the multivariable control schemes. These process simulation models were developed from results of an earlier EPRI-sponsored simulation study (AP-1740). This simulation requirement gives these methods a distinct advantage over conventional approaches, which do not encourage such early in-depth analysis.

The control designer continues the iterative process, applying the selected design approach to satisfy these criteria: stability, transient performance, disturbance rejection, robustness, and decoupling.

- Stability is the absence of continued cycling (or "hunting") and outputs remain bounded for bounded inputs.
- Good transient performance implies a smooth, prompt response to changes in controller set point.
- Disturbance rejection requires that controls compensate for anomalous process upsets that are often externally caused.
- Robustness and decoupling have become important with the evolution of multivariable control. Robustness implies overall stability and performance despite large variations in process behavior, external disturbances, or discrepancy between the design model and the plant.
- Decoupling allows two or more variables to be regulated independently, although the variables interact. Robustness and decoupling are features that are particularly germane to multivariable control methods.

The project team made many simulation runs during the control design process, using the original nonlinear models to assess the effectiveness of specific control algorithms against the above criteria. This early testing of computerized control algorithms uncovered errors and conveniently corrected them, using simulation to avoid difficulty during operation and to conserve time and resources.

Results

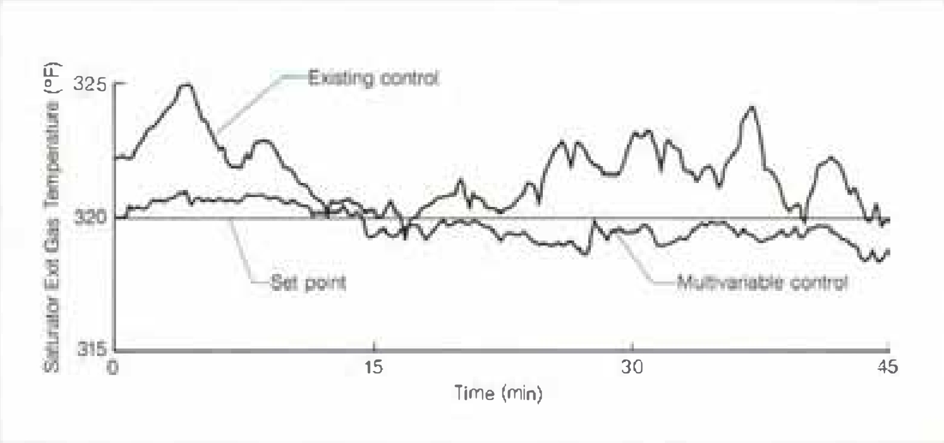
The control algorithms for the final control design were established experimentally on the process control computer without major flaws. However, transport delay or dead time in the liquid recycle loop impaired the system's initial performance. The interactive control design tools easily remedied this anomaly by promptly updating the linear models. The resulting designs performed very well.

By using multivariable methods, the coordinated control schemes greatly improved regulation of the saturator exit gas temperature (Figure 2). The new control systems also improved control of the temperature difference between inlet liquid and outlet gas. Without coordinated control, the temperature difference was not regulated and varied from 2 to 8°F; however, coordinated control held the same temperature difference close to the desired value of 4°F.

A major feature of the coordinated control system is the ability to decouple the interaction between closely related process variables. For example, the exit gas temperature responded steadily and smoothly as expected (over a 20-min period), following a planned step change in set point from 320 to 312°F (160 to 155°C). During that transient, the temperature difference remained close to its 4°F set point (i.e., it remained relatively unchanged from its normal steady-state response). This decoupling was achieved by precise coordination of the manipulated variables rather than by any change in the process itself. The coordinated controls were able to maintain regulation despite load disturbances. Moreover, the experimental results were accurately predicted by the simulation tests of the multivariable control design.

The above results were accomplished without the first condenser recycle, which was added in step two. The multivariable saturator controls performed reasonably in step two, although not as well as in the step

Figure 2 The trend recording of saturator exit gas temperature compares typical steady-state conditions under conventional (existing) controls with the improved response under coordinated (multivariable) control.



one configuration. The difference apparently resulted from unexpectedly low liquid flows in the reconfigured mode, which had not been run before in the PEF. Unfortunately, the DOE program schedule did not allow time to extend experimental testing to diagnose and correct the liquid flow deficiency.

Nonlinear process model conversion took more time and effort than expected; therefore, improved software is needed to automate model reduction. Both the time-domain and frequency-domain methods proved effective; the latter appeared better at decoupling. However, the study did not clearly show the superiority of one method over the other.

The project was a fair test of coordinated control design methods and the interactive software tools. In general, they were more than adequate for the task, formulating control designs promptly and efficiently. For example, the initial control design for the saturator was completely revised in less than six hours with accurate results, requiring no field adjustment.

The results clearly demonstrate that coordinated control with multivariable design methods is greatly enhanced by detailed analysis of operations carried out well beforehand. Not only can such methods improve control (e.g., robustness) of interacting processes, but they apparently expedite design procedures. Without such simulation and early analysis, conventional control designs frequently require considerable debugging and field adjustment. The multivariable control designs, which do not require significant field adjustment, can eliminate costly upsets and delays in commercial plant startup.

With the rapid development of powerful small computers and improved capabilities for dynamic process simulation, such coordinated control appears destined for more extensive commercial use, particularly for such emerging technologies as GCC power plants. *Project Manager: George Quentin*

PHOTOVOLTAIC SYSTEMS

A large number of photovoltaic (PV) power systems, ranging in size from tens of watts to several megawatts, have been built over the past five years. The smaller systems are generally such commercial applications as remote communication relay stations, which are not connected to utility grids. DOE has constructed residential systems of a few kilowatts and intermediate-size systems up to several hundred kilowatts, which have been interconnected with electric utility networks. Spurred by recent state and federal tax incentives, private developers have built megawatt-scale systems. The utility industry is beginning to develop a better understanding of PV technology from the field experience these megawatt installations provide. EPRI research focuses on development of modular central station systems. The objectives of RP1607 are to better understand PV system performance, operation, and maintenance and to characterize PV module performance. Conceptual designs for future PV central stations have recently been developed under RP2197.

Present technology

Over the past two years a cooperative program with DOE and Sandia National Laboratories (Albuquerque) has provided preliminary experience on both flat plate and concentrating systems. The primary data base comes from nine intermediate-size (18–225 kW) systems built under DOE sponsorship in 1981 and 1982. Five are flat plate systems, and four are concentrating systems. Two use parabolic trough reflectors, and two use Fresnel lens concentrators. As part of the program, Sandia funded the installation of an on-site data collection system. Under EPRI sponsorship (RP1607-1) Boeing Computer Services Co. collects, analyzes, and stores the data (AP-2544 and AP-3244). Beginning in December 1983, data are also being collected from a 1-MW system near Hesperia, California, constructed and operated by Arco Solar Industries.

Daily efficiency and daily capacity factor are the primary indicators of system performance. Daily efficiency is the fraction of usable solar energy incident on the array during the day that is converted to electricity. Daily capacity factor is the average power output of the array (over 24 hours) divided by the array's rated power.

Figure 3 shows 1982–1983 system performance data for two sites: the 100-kW flat plate system in Beverly, Massachusetts, and the 27-kW concentrating system in Dallas, Texas. Daily efficiencies that fall below the clustered values typically result from system outages for part or all of the day. Most of the outages have resulted from power conditioning and control system problems. Spaces with no data points represent problems with the data collection system.

The figure shows several items of interest: daily efficiencies drop about one percentage point in summer because of the higher array operating temperature (solar cell efficiency drops as cell temperature increases); system performance has improved at the Dallas site since the summer of 1983, as indicated by the reduced scatter in daily efficiency values and the reduced number of zero efficiency days.

Daily capacity factor combines system efficiency with daily sunshine to indicate how much electricity was produced compared with what could have been produced if the system had operated for 24 hours at rated output. The highest daily capacity factors are typically achieved in the spring and fall when the days are fairly long and ambient air temperatures are relatively cool. Maximum daily capacity factors of 20–30% are typical of fixed flat plate systems like the one at Beverly. Tracking systems can sometimes achieve daily capacity factors as high as 35–40%. However, cloudy days or system

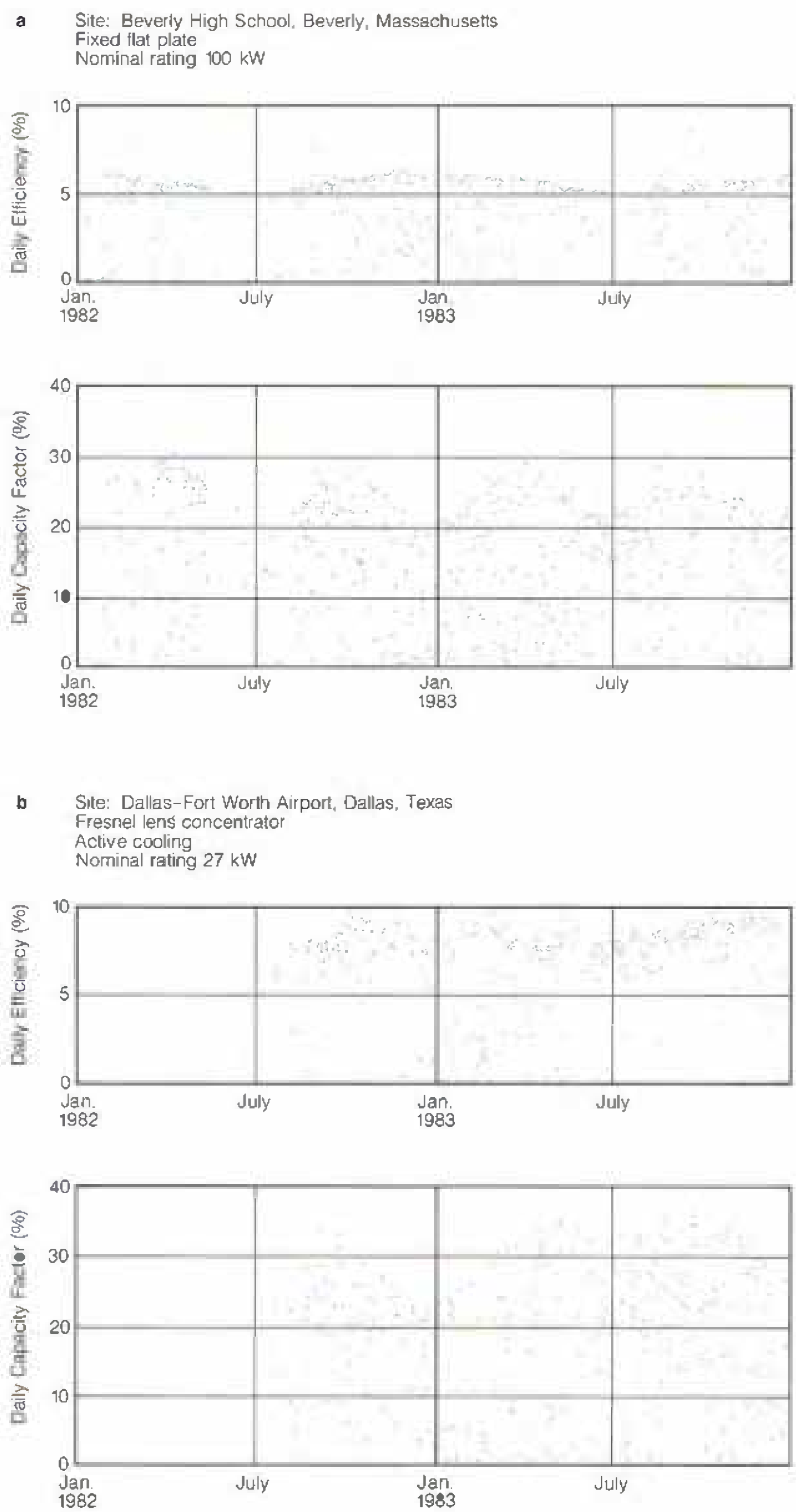


Figure 3 Daily efficiency and capacity factor for PV systems in (a) Beverly, Massachusetts, and (b) Dallas, Texas.

failures can significantly reduce daily capacity factors.

The collection and analysis of system operating data over many years will increase the understanding of mechanical and solar-resource-driven system reliability. Nearly two years of operating data have shown no statistically significant array performance degradation at the five flat plate or two Fresnel lens concentrator sites. A number of design problems caused severe degradation early at the two parabolic trough concentrator sites, and data are no longer being collected.

Several new sites will be added to the data collection network in the near future. Sacramento Municipal Utility District will begin to operate 1 MW of a potentially larger system during the summer of 1984; and a 325-kW system is being completed at Georgetown University in Washington, D.C. These newer systems and others in future years are expected to provide an increased understanding of PV power generation technology. Both efficiency and reliability should improve with these systems, which are being designed for unattended operation.

Future technology

Under RP2197 Black & Veatch Engineers-Architects has recently completed central station conceptual designs for 100-MW flat plate and concentrating systems (AP-3264). One primary objective of this project was to assess structural, wiring, and installation costs (so-called balance-of-system, or BOS, costs) for large PV systems. Fixed, one-axis tracking, and two-axis tracking flat plate systems and a high-concentration (500 suns) system were designed for a southwestern desert site and a southeastern Gulf Coast site.

BOS costs can be divided into area-related and power-related costs. Table 1 indicates the BOS costs estimated in this project. These figures include all direct costs except those for the modules. Using these BOS costs, assuming a 30-year plant life, regional solar availability, and other economic assumptions consistent with the EPRI Technical Assessment Guide (P-2410-SR), Figure 4 shows the trade-offs between levelized electricity cost, module efficiency, and module cost for the fixed flat plate and concentrating systems. In the Southwest, electricity generation at competitive costs (6–7¢/kWh, levelized over 30 years in constant 1983 dollars) requires flat plate modules with efficiencies of about 15%, if the module cost is about $100/m². For concentrating systems with cells of 27% efficiency, the allowable module cost (including sunlight-concentrating optical components) is about \$150/m². To generate electricity for 6–7¢/kWh in the Southeast requires higher module efficiency, lower module cost, or both. Because the sky is generally more overcast in the Southeast, concentrating systems are less attractive; very high efficiencies combined with very low module costs will be required to generate competitive electricity.

With a clear understanding of system requirements and a growing appreciation of actual system performance, EPRI's photovoltaics subprogram is now emphasizing performance improvement and cost reduction to help bridge the gap between present technology and future utility-scale PV central stations. *Project Manager: Roger Taylor*

Table 1
PHOTOVOLTAIC BOS COST ESTIMATES

	Flat Plate			
	Fixed	One-Axis	Two-Axis	Concentrator
Southwest				
Area-related (\$/m²)	50	60	90	100
Power-related (\$/kW)	180	200	190	175
Southeast				
Area-related (\$/m²)	40	50	90	100
Power-related (\$/kW)	170	185	175	160

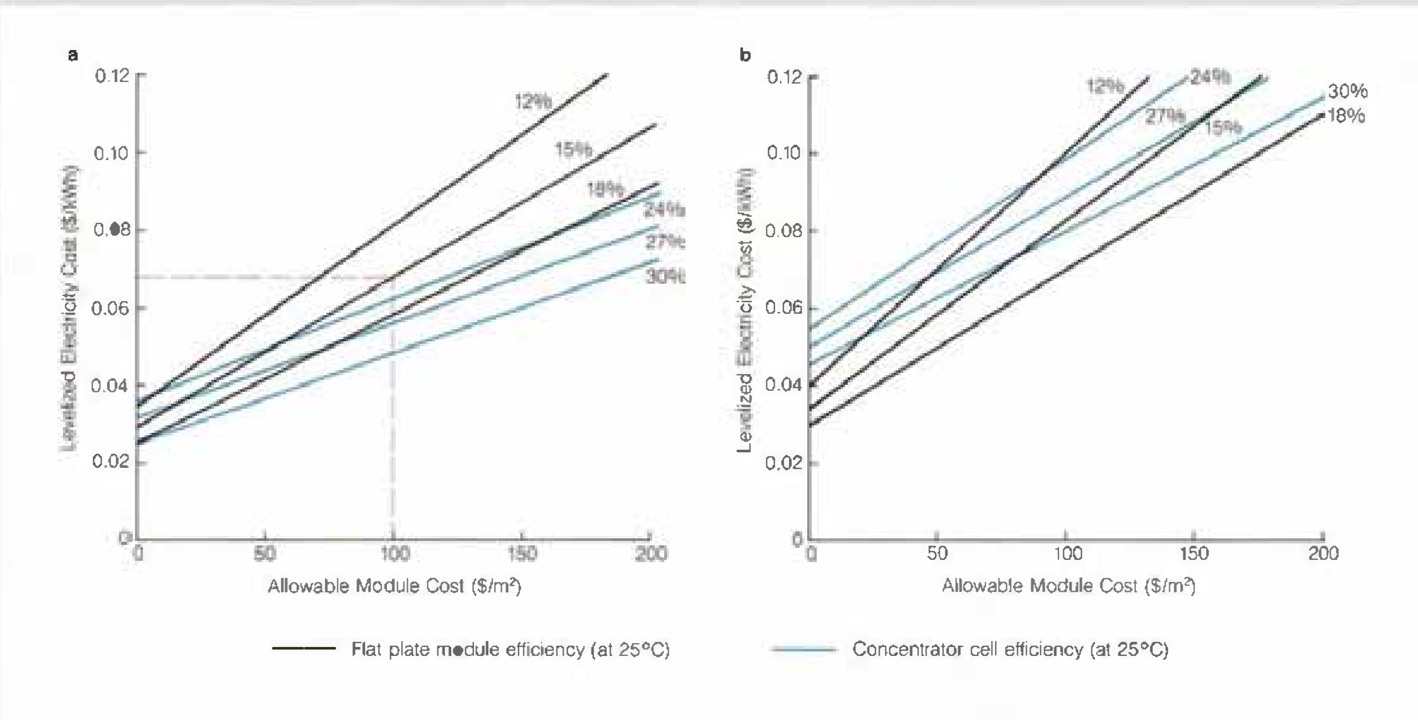


Figure 4 Cost/performance trade-offs for 100-MW fixed flat plate and concentrating systems at (a) a southwestern site and (b) a southeastern site. In the Southwest, for example, to generate electricity at a levelized constant-dollar cost of about 6.5¢/kWh, flat plate modules will have to be about 15% efficient if their cost can be reduced to \$100/m². (Costs are given in 1983 dollars.)

R&D Status Report
COAL COMBUSTION SYSTEMS DIVISION

Kurt Yeager, Vice President

COAL QUALITY IMPACT ASSESSMENT

Utilities must know the true cost of coal to determine which coal produces the most power at the least cost. Coal cost is defined not only by the cost of mining and delivering coal to a utility but also by the effect of coal properties on unit heat rate, availability, and maintenance. Accurate correlations of coal characteristics to power plant performance and costs would be of great benefit to utilities. EPRI has initiated a comprehensive program that will satisfy this need and provide utilities with a methodology for evaluating the performance and cost impacts of firing coals of different qualities in existing power plants.

Coal is a generic term for a family of solid fossil fuels with a wide range of composition, physical, and combustion characteristics. *Coal quality* refers to coal's value for a specific purpose, in this case electric power generation. Coal characteristics are known to significantly affect the performance of power plant components and the cost of generating electricity.

To quantify the impact of coal quality on the total cost of power generation and to develop the necessary data base, EPRI initiated a three-phase study (RP2256). In phase 1, which is nearing completion, Energy and Environmental Research Corp. (EER) extensively reviewed the literature and visited boiler manufacturers, architect-engineers, and utilities to evaluate the state of the art on coal quality effects. The objectives were to review current knowledge of coal quality effects, define R&D needs, and develop a research plan for phase 2. In addition to carrying out the plan, phase 2 will develop an overall methodology to quantify coal effects. Phase 3 will transfer the technology to the utility industry.

Coal quality effects

EER reviewed several coal quality/power plant performance studies conducted by utilities and other organizations and divided coal quality effects on power plant performance and costs into heat rate, availability loss, and maintenance costs.

Coal quality affects heat rate by changing boiler thermal efficiency, auxiliary power consumption, and turbine cycle efficiency. The key boiler heat losses result from dry flue gas loss, moisture in the flue gas, and incomplete combustion. These losses can be calculated for a particular coal quite accurately by measuring excess air and unburned carbon.

The effect of coal quality on the power consumption of plant auxiliaries other than the pulverizer can be determined straightforwardly by the excess air level. The parameter that most often links coal quality to pulverizer performance is the Hardgrove grindability index, which equipment manufacturers have related empirically to pulverizer capacity and power consumption. Discussions with manufacturers showed that these correlations are adequate for eastern bituminous coals but are inadequate for western coals and that other factors, such as moisture content, appear to be important.

Although EER did not investigate steam cycle components directly, they found that coal quality can affect turbine cycle efficiency. Steam conditions depend on furnace and convective pass heat absorption patterns, which coal quality may affect by its impact on heat transfer surface slagging and/or fouling, flame radiative properties, and flue gas weight. Heat distribution changes may prevent the plant from reaching superheat or reheat temperatures or may require excessive attemperation, which can significantly degrade turbine cycle efficiency. Accurate predictions of these effects are not possible at present because coal quality correlations with slagging, fouling, and flame radiative properties are uncertain.

Coal quality effects on availability are generally much costlier than effects on heat rate. Failures that cause partial or full outages and equipment limitations that reduce capacity (derating) are expensive. Equipment capacity deratings are currently predicted by using empirical indexes and experience with units in operation. According to equipment manufacturers, such correlations between coal quality and equipment capacity are fairly adequate for eastern bituminous coals but are inadequate for other coals. A statistical evaluation of the historical data base is the only method of correlating availability loss from equipment failures with coal quality at present.

Battelle, Columbus Laboratories conducted the most comprehensive data base analysis of coal quality–caused availability loss on data obtained from the Tennessee Valley Authority (TVA). The data included coal-related outage hours, boiler efficiency information, and maintenance costs for each unit or group of units; but the information on the quality of coal as fired was limited to ash, sulfur, and moisture content. Battelle found that an increase in ash content from 12 to 24% may increase a typical plant's outages by as much as 360 h/yr. Similarly, an increase in coal sulfur content from 1 to 5% may increase outages by as much as 870 h/yr. However, Battelle recommends that relationships derived from the TVA data should not be used outside the TVA system.

For the EPRI project, EER considered a wider but still-limited data base of 25 utilities in an attempt to correlate equivalent availability history with coal properties. The results showed that application of the Battelle-TVA correlation resulted in inaccurate trends and that accuracy improved when the correlations were based on the differences between actual coal properties and design coal properties and specific equipment design parameters. The study concluded that more-accurate correlations between coal quality and equipment performance require a more-extensive utility data base, detailed coal properties, and equipment design parameters, as well as more data on equipment failure causes.

Utility investigations show that the effects of coal quality on maintenance are extensive. The relationship between maintenance costs and coal quality, however, is difficult to assess because of the impact of non-coal-related factors, plant design variations, and utility-specific factors.

Utilities use a range of procedures to account for maintenance costs in coal-fired units that satisfy company needs but make it difficult to evaluate coal quality effects. For example, all tube failure maintenance costs may be identifiable but the fraction attributable to coal quality effects may not. The Battelle-TVA study developed maintenance cost correlations for the 56 TVA units. However, as with the availability correlations, the lack of a larger data base makes it difficult to apply the results to other units. A methodology and a utility data base have to be developed to correlate coal quality to the maintenance costs.

Coal characterization and combustion science

Figure 1 illustrates coal characteristics that affect the performance of power plant components. The most significant characteristics are those associated with coal mineral matter because these have a major impact on the performance of the pulverizer, the steam generator, and the fly ash removal equipment.

Table 1 summarizes coal quality characteristics and the measurements currently used to assess the performance of the three most important power plant components: the pulverizer, the steam generator, and the precipitator. Current state of the art relies on empirical indexes derived from experience with widely used coals. These indexes have limited applications for coals from new mines, low-rank coals, cleaned coals, and coal blends, which utilities are actively considering for economic and environmental reasons. A fundamental understanding of coal characteristics and combustion processes is needed to improve current knowledge of the effects of coal quality on power plant performance.

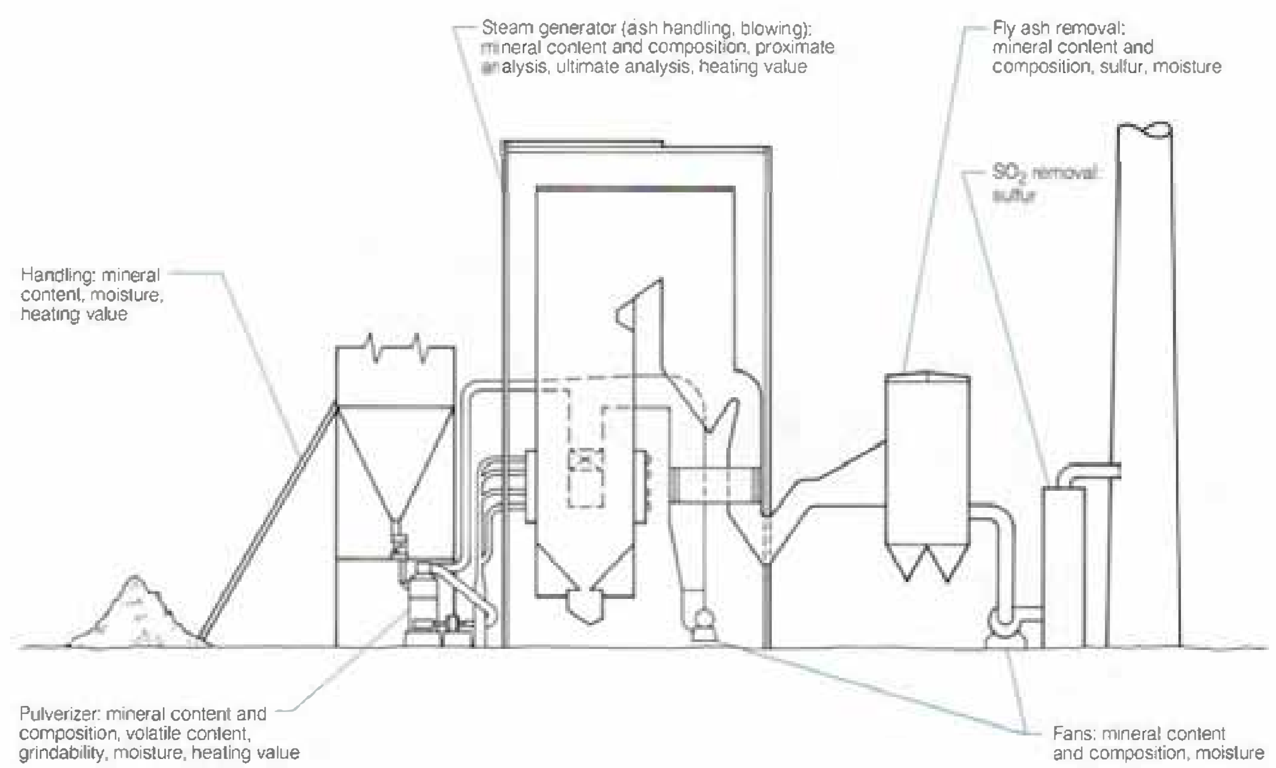


Figure 1 Coal quality can affect the performance of virtually all power plant components—most significantly, the pulverizer, the steam generator, and the fly ash removal equipment. The most vital coal property dictating plant performance is the mineral content of the coal.

Table 1
COAL QUALITY MEASUREMENTS AND THEIR LIMITATIONS

Component	Measurement	Description	Limitations/Remedies
Pulverizer	Hardgrove grindability index	Measures coal grindability; manufacturers' empirical correlations relate HGI to pulverizer capacity and power requirements	Existing correlations do not apply to western coals and coal blends; need improved tests and understanding of coal comminution
	Free quartz index	Indicates coal abrasion characteristics in pulverizer, pipes, burners, and other equipment	Conflicting evidence as to usefulness; size and amount of quartz may be more meaningful; need abrasion tests
Steam generator	Ratio of volatiles to fixed carbon, burning-rate profile	Standard measurements indicate flame stability and coal burnout characteristics	Tenuous relationship; burnout not a problem with most U.S. coals; coal particle combustion kinetics needed for boiler performance model
	Slagging indexes, fouling indexes, corrosion indexes	Empirical indexes based on coal ash analyses; experience used to relate to boiler design and size	Based on whole coal; do not account for heterogeneous nature of pulverized coal; research under way using density and size fractions; need research to define steam generator conditions and mechanism of mineral matter transformation and deposition
	Erosion index, ash content and composition	Experience used to relate to convective pass tube spacing	Major impact on availability; need research to establish test procedures
	Emissivity/thermal conductivity of deposits	Experience and combustion testing used to define values	Need test procedures and determination of relationship to coal properties and to boiler design/operation
ESP	Ash content and composition, SO_2/SO_3 concentration, resistivity	Empirical correlations based on experience and models to predict performance	Current procedures may not be adequate for all coals; need to determine relationship of fly ash to coal properties and boiler design/operation

Coal is usually characterized by analysis of a whole coal sample, and because quality can vary within a sample, this type of analysis is inadequate. Recent research on pulverizers shows that the coal sample in the pulverizer grinding zone has higher concentrations of such minerals as quartz and pyrite than does the feed coal (RP1883).

The Hardgrove grindability test is applied to the whole coal under conditions not representative of commercial pulverizer operation, and although it satisfactorily measures eastern bituminous coals, the process needs modification for western coal and coal blends. The amount of free quartz has been used in the past to indicate coal abrasiveness in pulverizers. Recent research shows that the size and amount of the abrasive mineral may be meaningful in relating coal properties to pulverizer wear.

After pulverization, the individual coal particles may not have the same analysis as the whole coal, and yet particle composition and subsequent history have a major effect on slagging, fouling, corrosion, and erosion in the steam generator. Some particles may be entirely mineral matter; others may contain organic materials with mineral inclusions or with minerals attached to the coal structure itself. When the coal particles burn, some of the more volatile minerals, such as those containing sodium, may vaporize and subsequently condense on tube surfaces or ash particles. Or they may cluster to form a very fine particulate.

The mineral matter that remains with the coal particles is heated by the combustion process and may undergo complex physical and chemical changes, depending on the particle environment. Minerals can combine within a single particle or by particle collisions to form other compounds with much lower melting points. As these processes occur, the particles are transported through the furnace and convective pass. Some may adhere to furnace surfaces (slagging); others may become lodged in the convective pass (fouling). Sodium and sulfur compounds diffuse through these deposits and can cause corrosion. Some particles may be abrasive and, depending on their state and aerodynamic transport, may cause tube erosion.

Most manufacturers use empirical indexes based on ASTM coal properties as guides to account for coal's potential for slagging, fouling, corrosion, and erosion in steam generator design. These indexes are sometimes supplemented by coal tests in small-scale combustion test furnaces. However, accurate quantitative correlations between coal quality and steam generator performance require understanding complex combustion processes. Advanced diagnostic processes are being developed and used to aid this R&D effort.

Electrostatic precipitator (ESP) performance depends on the amount and the properties of the fly ash leaving the steam generator. Empirical correlations and models have been developed relating coal properties to ESP performance and these appear to be reasonably adequate for most coals. Greater understanding of steam generator processes is required to improve prediction of the fly ash characteristics and ESP performance.

EPRI R&D plan

Review of the knowledge of coal quality effects on plant performance shows major gaps in the understanding of coal characterization and combustion, particularly on the fate of coal mineral matter. To fill these gaps, EPRI has prepared an R&D plan for developing a methodology that will enable utilities to quantify coal quality effects on existing plants.

The plan has three major elements: basic research, component performance, and coal quality effects. To avoid an open-ended research program, EPRI will design and conduct selected field tests that will restrict the research to practical utility applications. The component performance projects will use the research results to develop and/or improve models for predicting component performance. The coal quality analysis projects will integrate the research results, continuously modify and update the plan, and provide a methodology for quantifying the effects of coal quality on plant performance and costs.

This plan will integrate several EPRI research projects already in progress, including studies on fossil fuel plant availability (RP1266), combustion characterization of cleaned coals (RP2425), slagging and fouling (RP1891, RP1839), pulverizer reliability (RP1883), advanced power plant performance diagnostics (RP1681, RP2153), and fuel planning and management (RP2359). *Project Manager: Arun K. Mehta*

HIGH-INTEGRITY SURFACE CONDENSERS

A leaking condenser can be the root cause of the failure of many components exposed to a power plant's steam-water cycle, and utilities worldwide are therefore interested in improving surface condenser design and operation. The contamination of the steam condensate by cooling water from leaking tubes and tubesheet joints and by air from leaking expansion joints, valve stems, and other components results in numerous corrosion problems in feedwater heaters, fossil fuel boilers, nuclear steam generators, low-pressure steam turbines, and in the condenser itself. Operating plants over a wide range of loads may exacerbate both operational and shutdown problems. One of utilities' primary concerns about cyclic duty is that frequent unit startups can accelerate corrosion rates if the condensate contains high levels of dissolved oxygen.

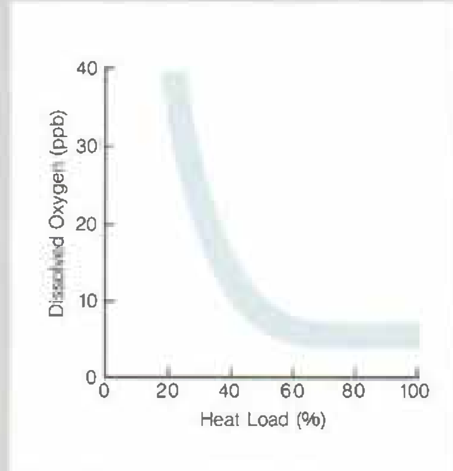
The use of tracer gases, such as helium and halogens, has enabled many utilities to locate and repair small individual cooling water leaks during reduced-load operation. In addition, a number of utilities have upgraded their fossil fuel and nuclear plant condensers by installing more corrosion-resistant tubing and tubesheets. The improvement in condensate quality has been significant. The use of nondestructive (eddy current) examination is being expanded.

If air leaks into the condenser steam side and is absorbed by the condensate, its presence in the condensate can increase corrosion rates in carbon steel and copper alloy feedwater heaters. If ammonia is also present, air leaks can cause condensate corrosion and stress corrosion cracking in copper alloy condenser tubes. This corrosion is a problem in itself, but corrosion also produces metal ions (e.g., Cu^{++}), which are carried through the feedwater heaters into the boiler or steam generator and into the steam turbines, where they can be reduced with concomitant metal oxidation. Thus, corrosion can be stimulated in the absence of oxygen because of the presence of reducible metal ions that were formed earlier in the cycle when oxygen was present.

Other metal ions produced in the condenser and feedwater train as a result of oxygen ingress can precipitate as a sludge in the steam generator. This sludge can provide a location for the hideout and concentration of contaminants and water treatment chemicals, which stimulate general corrosion or stress corrosion cracking.

Several approaches are available for countering feedwater train corrosion and other deleterious air inleakage effects. The most effective but most arduous of these methods is locating and eliminating the leaks themselves. This procedure requires an inventory of all valve packing glands, expansion joints, and other potential leakers and the initiation of a regular inspection and maintenance schedule. However, effective deaeration in all areas is nearly impossible if air inleakage rates are very high. In addition, condenser deaerating performance deteriorates rapidly at low heat loads—for example, less than 50% of full load (Figure 2).

Figure 2 Deaeration of most condensers deteriorates at lower load operation and becomes quite ineffective at startup and very low loads.



EPRI is planning to evaluate three condenser retrofits in a demonstration plant to improve condenser deaerator performance during no-load and low-load operation (RP1689-13). One improvement will be the installation of bubbling deaerator devices below the tube bundles (or in a condensate slipstream outside the condenser). Another will increase vent flow from the condenser by using a steam-jet chiller with a spray condenser in the air off-take line between the condenser and the vacuum pumps. A third method will install a booster jet and after-condenser between the condenser and the vacuum pumps. A symposium on preventing condenser failures will be held in Palo Alto, California, November 13–15, 1984. *Project Manager: R. L. Coit*

R&D Status Report
ELECTRICAL SYSTEMS DIVISION

John J. Dougherty, Vice President

TRANSMISSION SUBSTATIONS

Pyrolysis and combustion of PCBs

As regulations appear to be tightening in the handling and phasing out of askarel-filled equipment (*askarel* is the generic term for PCB and mixtures with tri-/tetra-chlorobenzene), other transformer insulation fluids also require attention. One of these is any mineral oil that has been inadvertently contaminated with PCBs. During the period when PCBs were not considered a problem, many transformers were contaminated either by the manufacturer or the utility when they used common liquid transfer equipment for both PCBs and mineral oil. Several million of these transformers contain 50–500 ppm PCB in the mineral oil and are by regulation considered contaminated. A small fraction of the mineral oil transformers containing PCB are above 500 ppm, and these are legally classified as PCB transformers.

A second problem area is that of retrofilled equipment. The mixture of liquids in a transformer after initial retrofill normally is found to have 2–5% of the original PCB remaining; therefore, virtually all retrofilled transformers are still legally PCB transformers.

The EPA plans new rules for initial issuance in October 1984; it is paying particular attention to PCB transformer fires, in which partial oxidation products, such as polychlorinated dibenzofuran (PCDF) and related compounds, might be found. EPRI initiated a project (RP2028-4) with the New York State Department of Health to determine the rate of formation of PCDFs under conditions of pyrolysis and combustion. Tests will initially be made with concentrated askarels to standardize operating techniques. These will be followed by trials using the same askarels as 5% and 500 ppm contaminants in mineral oil and several potential retrofill fluids, such as silicone, perchloroethylene, and RTEmp. Significant input from this project will be available in time for the initial EPA rule proposals, while further results will be ready for the public comment period on the proposed rules near the end of 1984.

Early experiments to determine optimal operating conditions are progressing satisfactorily and the work is proceeding on or ahead of schedule. *Project Manager: Gilbert Addis*

PCDF in utility equipment

As a result of recent fires involving PCB transformers (e.g., in Binghamton and San Francisco), there is an increasing need for improved PCDF analysis. PCDF, a partial oxidation product of PCB, has been found in the combustion products of fires involving PCBs. Conceivably, it also could be found in equipment where PCB or PCB-containing insulating fluid has been subjected to a variety of abuses, such as arcing, corona discharge, or long-term elevated-temperature operation.

The interest in improved analytic methods for PCDFs has two roots. First, in a series of animal tests, certain of the PCDFs (there are 135 different species, called congeners) show as much as 1000 times the toxicity of PCBs. Although the hazard of human exposure has not been directly related to the animal tests, both EPA and the public are increasingly concerned. The second need for the improved analytic methods arises from the fact that PCDFs themselves vary over a range of more than 1000 to 1 in the animal toxicity tests. Currently, lacking better analytic capability, EPA assumes the toxicity of a mixture to be the worst case, as if it all consisted of the most toxic of the family (2,3,7,8 PCDF).

In RP2028-5, -6, -7, -8, -9, started in January 1984, four contractors are working together on improving the state of the analytic art—Radian Corp.; Illinois Institute of Technology Research Institute (IITRI); Battelle, Columbus Laboratories; and New York State Health Dept. Professor Christoffer Rappe of the University of Umea, Sweden, a Battelle consultant, is also participating. In this phase of the project fresh PCB fluids will be analyzed for PCDF content. Meanwhile, General Electric Co. is supplying information on sampling generic types of equipment to achieve the second goal of the project, which is to determine under what conditions, if any, PCBs are found in utility equipment.

In the first stage of the work, Radian began careful synthesis of carbon-13-substituted spiking compounds. These compounds are added to the mixture to be analyzed before undertaking the extensive cleanup process. They have the same chemical properties as the natural carbon-12 compounds that we are quantifying in the analysis, but they show up as unique beacons in the mass spectrograph and can be used to determine the percentage of natural compounds lost in the cleanup and thus aid in calibrating the analysis for specific compounds. Meanwhile, General Electric selected types of equipment to be sampled, and Battelle is undertaking the acquisition of samples for the second phase of the project. *Project Manager: Gilbert Addis*

ROTATING ELECTRICAL MACHINERY

New austenitic alloy for retaining ring application

The capacity, efficiency, and reliability of modern electric generators are governed to a great extent by the strength of retaining rings, which are among the most highly stressed components in a generator. The purpose of these rings is to hold the end turns of the copper field winding in the rotor against centrifugal force. Currently, the ring material predominantly used in large generators is an iron-base, austenitic alloy, containing about 18% Mn and 5% Cr, which must be cold-expanded to achieve the desired high strength levels. This alloy has limitations in terms of its strength level, resistance to stress corrosion, and domestic manufacturability. To address these concerns, EPRI sponsored a project at the University of California at Berkeley to develop a stress-corrosion-resistant alloy that would provide high yield strengths (200 ksi, 1.4 GPa) through hot working and heat treatment alone. The research was successful, and an alloy called alloy T was developed.

EPRI initiated a follow-on study (RP1876) at General Electric to investigate the possibility of producing lower-cost, Nb-modified versions of alloy T, to characterize their mechanical and physical properties, and to demonstrate the feasibility of manufacturing full-size rings. Specifically, RP1876 has two primary objectives.

- To perform generator design studies quantifying the advantages to be gained from improved retaining ring material properties, particularly higher strength and increased resistance to stress corrosion
- To evaluate the properties of a modified, less-costly version of alloy T and to demonstrate its applicability to retaining rings by scale-up studies

The generator design studies have now been completed (EPRI EL-3169, July 1983). Results show that for an 840-MVA generator, the use of a 200–220-ksi (1.4–1.5-GPa) yield strength ring could reduce losses by about 600 kW relative to a reference design based on 145-ksi (1-GPa) rings typically used for generators of this rating. For the 1320-MVA generators, the calculated loss reductions were 410 kW for a design using 200-ksi (1.4-GPa) rings and 730 kW for a 230-ksi (1.6-GPa) ring design, compared with a reference design using currently available 175-ksi (1.2-GPa) rings. The results also show that rings with yield strengths above 230 ksi (1.6 GPa) could not be beneficially used in a 1320-MVA generator. The savings from these losses can be estimated on the basis of $1000/kW.

The results of the reliability studies showed only a small operational savings by the use of stress-corrosion-resistant rings because of a generally favorable service experience with 18Mn-5Cr rings in the limited data used by General Electric and because repairs or ring replacement was accomplished quickly when corrosion-related problems occurred. The analysis further showed that the savings are a very sensitive function of the forced-outage time and the cost associated with the procurement of a replacement ring.

Results of laboratory metallurgical studies using 300-lb (136-kg) heats have shown that the 3% tantalum in the EPRI alloy T can be partially replaced with niobium (1Nb + 1Ta) without compromising any of the property requirements. Metallurgical and processing studies show that the modified alloy is capable of achieving yield strength levels of 200 ksi (1.4 GPa) or more, with ductility and toughness levels comparable to the currently used 18Mn-5Cr alloy and with superior stress corrosion resistance. The modified alloy also shows a greater spread between the tensile and yield strength levels than does the 18Mn-5Cr steel. Scale-up studies are currently in progress. A 5000-lb (2.3-t) heat of the modified alloy has been cast and forged into billets successfully. It is anticipated that production of three rings from this forging will be completed in the next two months.

To consolidate worldwide experience with respect to materials design, operation, and inspection aspects of retaining rings, a major workshop (attended by representatives of utilities, generator manufacturers, universities, and ring manufacturers) was held in Palo Alto, California, in October 1982. Proceedings of the workshop have been issued as an EPRI report (EL-3209). *Project Managers: R. Viswanathan and D. Sharma*

OVERHEAD TRANSMISSION

Radio interference from transmission lines

Present theories of radio frequency interference (RFI) emitted from transmission lines do not correctly explain effects measured in the field. Information for transmission line design is obtained from empirical data taken from a few short line tests.

A comprehensive theory in a computer model to calculate radio frequency fields from transmission lines is being developed by Washington State University (RP2025-1). This model will predict correctly and completely the electric and magnetic fields emanating from a transmission line in corona. The fields will be calculated for ranges beginning directly beneath the line and continuing outward to several miles from the line. The model will include a sophisticated corona plasma source and various line configurations, and it will account for the conducting and dielectric properties of the earth. The presence of towers and shield wires will also be considered within the model.

At the conclusion of this research, a computer program will be available to member utilities through the EPRI Software Center and through the EPRI work station (RP2016). Representative cases will be provided in the EPRI handbook *Transmission Line Reference Book—345 kV and Above*.

Electric and magnetic field measurements as available from transmission lines will be used to verify the theory and the computer model. *Project Manager: W. E. Blair*

UNDERGROUND TRANSMISSION

Fault location

As described in the June 1983 issue of the *EPRI Journal*, the rapid location of faults in underground transmission systems is necessary to minimize costs and maintain adequate system reliability.

The prototype fault location system developed by Hughes Research Laboratories (*EPRI Journal*, September 1980, contains a description of its operation) can potentially meet this need (RP7874).

Although this system has operated successfully in the laboratory, it is necessary to verify its operation in the field on one or two real transmission systems. EPRI is seeking a utility that may have a cable system, either pipe-type or self-contained, in which a fault can be staged to test the equipment. Any information on the availability of such a system should be conveyed to the EPRI project manager. *Project Manager: Felipe G. Garcia*

DISTRIBUTION

XLPE and HMWPE cable failures

Electric distribution systems throughout the United States have used high-molecular-weight polyethylene (HMWPE) and cross-linked polyethylene (XLPE) insulation in buried 15–35-kV urban distribution systems for more than 15 years. The failure rates for these systems started out low; however, as time progressed and the older cable aged, failure rates started to increase. Also, as increasing quantities of cable were being installed every year, cumulative failure rates increased each year; currently the values range from 3 to 25 failures per 100 mi (161 km). These values are industry averages; some individual utilities are experiencing even higher failure rates for some insulation types.

As increasing numbers of the HMWPE- and XLPE-insulated cables continue to fail in service, a better understanding is required of the causes for these failures. In 1981, Battelle, Columbus Laboratories undertook a four-year project to seek the causes of premature cable failure (RP1782-1). A two-phase project was funded: phase 1 involved collecting data from utilities on cable failures, cable construction, and cable operating conditions, and developing a hypothesis for the major causes; phase 2 involves the testing of that hypothesis. This article covers phase 1 of the study, which is now complete.

The approach employed by Battelle involved an analysis of historical data provided by utilities. The data consisted of such items as the following: utility, insulation material, miles of cable installed annually, annual failures, insulation wall thickness, tape/extruded semicon material, operating voltage, transient surge protection level, isokeraunic level, cumulative conductor miles, use of dc testing, other fault locating methods, direct-buried or in duct, direct burial method, climate, and so on.

Phase 1 concerned the acquisition of data for HMWPE- and XLPE-insulated cables from the participating utilities, the development of a computerized data base from utility-provided information, and a statistical analysis of the data base. This was a new approach for studying this problem.

Over 20 utilities were involved. Useful data were collected for over 80,000 mi (123,720 km) of cable. The data received were screened, entered into a computer, and analyzed in a search for parameters that might be predictors of high cable-failure rates. Of those utilities involved, useful data were available from 15 (representing about 80 mi [130 km] of installed cable). Statistical analysis, however, was inconclusive because the age-related data were inadequate. Similar analysis of a three-utility subset provided more meaningful results. For these data, the entire failure history of each year's supply of cable installed was available and could be plotted separately as annual failure rate versus cable age. The results are summarized in Figure 1.

The most important parameter was material nature (HMWPE having higher failure rates by all definitions employed). Age was second in importance; beyond this the two insulations differed from each other in important parameters: for XLPE, it was wall thickness followed by the specific year of installation; for HMWPE, it was voltage stress (Figure 2) followed by either insulation wall thickness for cables at less than 2.0 kV/mm operating stress (the thicker the wall, the lower the failure rate) or the specific year of installation for cables at higher operating stress.

Phase 1 generated recommendations for improved cable failure data collection procedures. Also, a modified method for estimating failure rate was suggested as being more meaningful: failures per 100 mile-years (which compensates for age) rather than failures per hundred miles. This age com-

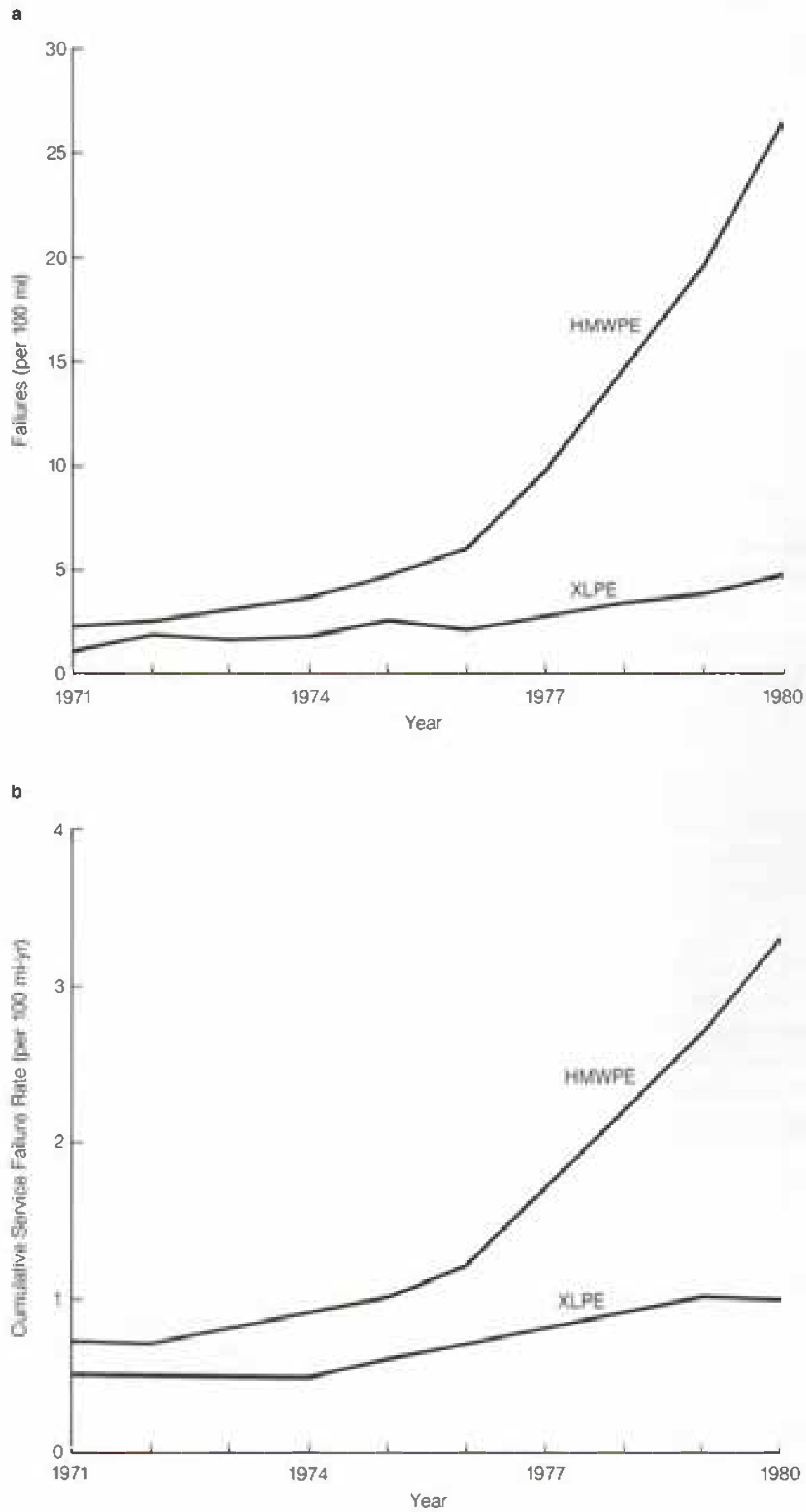
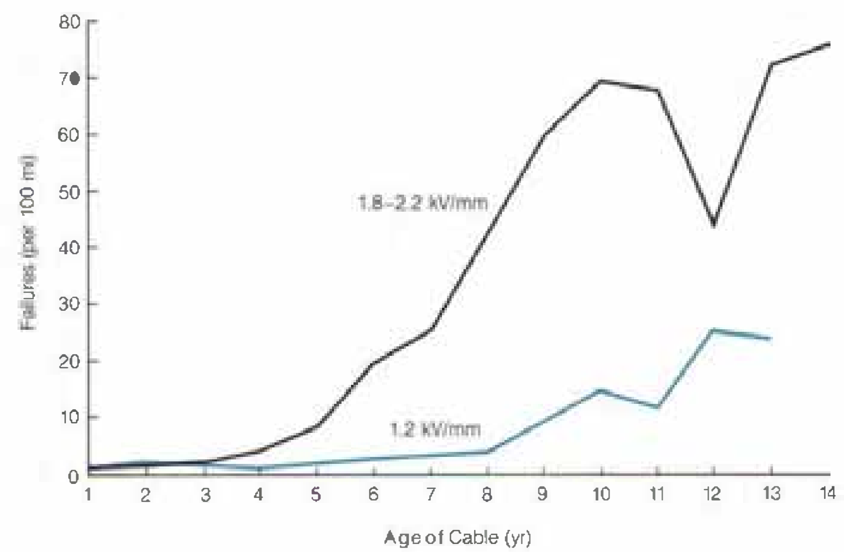


Figure 1 These graphs demonstrate the significance of the method used for calculating failure rate. Cumulative failure rate data (a) show a greater rate of increase than age-related failure data (b). The conventional calculation method (a) indicates a sharply increasing rate for HMWPE but a slightly increasing rate for XLPE because HMWPE has been used for a longer period of time (and therefore has had more failures).

Figure 2 These data indicate that HMWPE failure rates are operating-stress related; those cables operating at higher stresses show a markedly higher failure rate.



pensation parameter shows that HMWPE performance is slightly better and XLPE performance is slightly poorer than the more conventional reporting method. The phase 1 results confirmed some industry trends, and located some weaknesses in evaluating failure information; the suggested changes will help future understanding. *Project Manager: Bruce Bernstein*

Guideline to evaluate distribution automation and load management

A guideline has been developed to assist utilities in planning and evaluating distribution automation and load management systems (RP2021-1). This guideline addresses cost-effectiveness of deferred plant, improved utility operations, increased system reliability, reduced manpower requirements, and increased equipment lifetime. In addition, benefits can be evaluated for providing more-rapid response to emergency situations, as well as more information and data for managers. It is intended that the guidelines will be sufficiently versatile so a broad range of utilities (large and small, urban and rural) will be able to make complex decisions when implementing distribution automation and load management systems.

The methodology in the final report provides a general, step-by-step procedure for assessing economic feasibility and revenue requirements for conventional and automated expansion.

With the guideline each utility can develop its own computer program, assemble its own data base, and apply a financial model unique to its system. *Project Manager: W. E. Blair*

Communication systems for distribution automation and load management

Research continues on improvements in two distribution communication technologies: power line carrier and radio. Westinghouse Electric Corp. has completed a follow-on contract (RP850-32), with Detroit Edison as host utility (RP850-33), to develop and test an improved power line carrier communication system. This research is a follow-on to that completed earlier (EL-1860, Vols. 1–4) and reported in the *EPRI Journal* (May 1982).

Three specific tests were conducted to verify communication performance that would satisfy utility requirements for distribution automation.

- The first two-way communication performance to secondary points (e.g., remote meter reading) must exceed 95%.
- Every remote point must be contacted every day.
- The performance must not degrade after feeder sectionalizing.

To verify performance, Westinghouse installed load management terminals (LMTs) at 90 random remote points on an H-shaped feeder. The system was tested for six months with the following results. The feeder system was sectionalized into three configurations and the communication performance exceeded 96% before and after all sectionalizing cases. All but one LMT (equipment failure) were correctly contacted during 180 days from April through September 1983. As a result of these tests, it was verified that the Westinghouse power line carrier communication system will satisfy utility requirements for distribution automation. It is anticipated that this communication system will be used in large-scale integrated distribution automation system tests (RP2592). Such research will be reported later this year. *Project Manager: W. E. Blair*

POWER SYSTEM PLANNING AND OPERATIONS

Power plant performance

The objective of RP2153 from the power system perspective is improvement in the accuracy of heat rate data and system economic dispatch. From the plant perspective, the objective is improvement in plant heat rate and plant availability. An advanced, computer-based plant performance instrumentation system is being developed for prototype installation in an existing fossil fuel plant of Potomac Electric Power Co. (Pepco), the host utility. Morgantown Unit 2, a 565-MW supercritical unit, is being used as a demonstration facility. This instrumentation system is being designed and developed to provide continuous detailed analysis of the unit performance to a utility's plant engineering, plant operations, power supply group, and system control center. The integrated system is expected to improve overall plant efficiency by 1–2%. Development of this prototype system will provide the utilities with information on those improved operating procedures, as well as additional devices and operating procedures, that were selected and/or developed, tested, and found to be of substantial benefit.

Pepco is the prime contractor and host utility. Subcontractors include Power Technologies, Inc.; Lehigh University; Combustion Engineering, Inc.; and General Electric Co. The project is jointly sponsored by two EPRI divisions, Coal Combustion Systems (RP1681) and Electrical Systems (RP2153).

An analysis of generating unit performance modeling and measurement uncertainty for economic dispatch was one of the early tasks in this project, with the following goals.

▫ Develop a scheduling and dispatch simulator capable of recognizing and evaluating the effects of different methods of economic dispatch, capable of recognizing the impact of changes in unit operating conditions, and capable of performing cost studies over periods of time up to one month

▫ Develop a set of appropriate indexes that can monitor the effects of inaccuracy or uncertainty in input/output measurements and dispatch model inaccuracy

▫ Develop analytic methods appropriate for setting confidence intervals for constrained curve fits and develop analytic methods for predicting and monitoring the significance of errors in input/output models on scheduling and economic operation

▫ Determine the sensitivity of the cost and dispatch performance indexes to changes in incremental heat rate models used in economic dispatch and determine the sensitivity of incremental heat rate to changes in unit operating conditions

To demonstrate the accuracy of the dispatch simulator, comparisons of total heat input were made for an October 1982 study period, using Pepco fuel use, generation, and Btu summaries. The comparison indicates that the dispatch simulator is quite accurate, taking into consideration the differences between real-life dynamic conditions and input/output data modeling and measurement accuracy. The following conclusions were drawn from the analysis.

Process changes on individual units resulted in appreciable changes in calculated system fuel consumption and cost. Strongest impact and greatest sensitivity are with exhaust pressure deviation from design. On one cycling unit, a positive 0.75-in (2.54-kPa) pressure deviation in exhaust pressure resulted in an increase in calculated system fuel cost of $2125/day (24 hours), or 0.3% of system daily fuel cost.

Errors in incremental heat rate result in errors in dispatch and increases in production cost. For the October 1982 study period, relatively small dispatch shifts (errors) were observed for the test system; the calculated increases in fuel consumption were small if the results were run as designed and changes in main steam pressure were limited to 25°F or if condenser back pressure was limited to 0.75 in. The two significant limits to realizing the improvements possible with more-accurate observations and corrections for unit operating conditions are the limitations of conventional dispatch algorithms (convex input/output curve requirement) and accuracy limitations of unit performance measurement.

The requirement for convex input/output introduces a modeling error into the input/output curve fit of approximately 0.25–0.3% rms and 0.8–1.0% maximum for the study units. This modeling error is caused by fitting a convex input/output curve through the mean of the discontinuity caused by sequential opening of the valves (valve loops). The error provides a limit for the accuracy of input/output and incremental heat rate representations for conventional dispatch algorithms. Modeling errors as small as 1% of maximum input fully mask changes in either unit main steam conditions up to 25°F or condenser back pressure up to 0.75 in.

Performance measurement uncertainty (random errors in data scatter that create nonrepeatability) can have a significant effect on system operating costs. For the test system, performance measurement uncertainty becomes significant at levels above 2% of rated unit input. The effects of performance measurement uncertainty errors of 1% of maximum input fully mask changes in either main steam conditions up to 25°F or condenser back pressure up to 0.75 in.

Modeling errors and performance measurement uncertainty can be most significant for marginal units on economic dispatch.

Performance measurement bias can have a significant effect on system operating costs. Incremental displacements of the complete unit incremental heat rate were used to simulate bias effects. The influence of bias errors (within a confidence interval) in performance measurements among the set of dispatchable units must be reduced to less than 1% uncertainty to avoid masking the effects of unit dispatch scheduling.

Other work includes dispatch system review; boiler performance testing; an N2 packing measurement system; the design and procurement of a condensate flow section that will meet ASME PTC-6 requirements; a parametric analysis of the boiler; and waterwall tube wastage measurement.

Three reports on the results accomplished thus far will be available during the third quarter of 1984. The topics are boiler, general cycle, and economic dispatch. The present phase of the work will continue through the first quarter of 1986. *Project Manager: John Lamont*

R&D Status Report
ENERGY ANALYSIS AND ENVIRONMENT DIVISION

René Malès, Vice President

ECOLOGICAL MICROCOSMS AS AN ASSESSMENT TOOL

Hazardous chemicals released to the environment may pose a threat to ecosystems and human health, but protocols for testing the environmental behavior of these chemicals are commonly too simplistic for extrapolation or too complex for analysis. Experimental preparations called microcosms may be useful as a way to reconcile the extremes of current test methods. Such microcosms range in complexity from bioassay scale to field plot scale. Toward the goal of providing tools for the assessment of toxic effluents, EPRI has funded six projects in microcosm development.

Aquatic microcosms

In RP1224-1 Lawrence Berkeley Laboratory conducted a series of experiments to evaluate the use of lake microcosms for toxicologic testing (EPRI EA-1989). Several different microcosm configurations were studied; the variables included container size (from 4 to 200 L), the method of preventing algal surface growth, and the degree of water mixing and aeration.

In all but the smallest microcosms, algal surface growth was successfully prevented. Concentrations of chemical nutrients in the microcosms matched well with those for the parent lake except during periods when nutrient inputs to the lake from the surrounding watershed were high. Good tracking of phytoplankton succession patterns was observed only when the physical conditions of the lake and of the laboratory system corresponded closely.

To study a possible application of lake microcosms, decomposition experiments were conducted. Dead organic matter was added to the microcosms, and subsequent mineralization activity was monitored. Highly replicable and interesting short-term behavior was seen; the results imply that protocols can be developed for microcosm testing of toxicant effects on mineralization rates. On the basis of both the decomposition and microcosm assessment studies, it appears that applications of lake microcosms are useful but limited.

In RP1224-4 Battelle, Pacific Northwest Laboratories developed and tested a microcosm for investigating the effects of chlorine on marine benthic (bottom-dwelling) communities (EA-2696). The electric utility industry has found chlorination to be an effective means of biofouling control. In using chlorine for this purpose, utilities have a choice between continuous and intermittent control regimes, as well as options regarding the concentration of chlorine-produced oxidants (CPO) in cooling structures. The objective of this research was to identify community- and ecosystem-level responses to different chlorination regimes and CPO concentrations in experimental seawater systems.

During the tests raw seawater was pumped through an array of microcosms, which were colonized by propagules of the organisms present in the water. Chlorine was applied on intermittent and continuous schedules and at CPO concentrations of 10 and 50 ng/mL. The researchers measured the rate and extent of colonization for two years. They monitored the amount of CPO produced in the chlorination treatments relative to the amount of CPO applied, as well as several biologic parameters that might be influenced by chlorination.

Differences in the growth of species richness between control (no chlorination) and intermittent regimes were not significant. As compared with intermittent treatments, the treatments featuring continuous chlorination showed a significantly lower growth rate for species richness. The study data indicate that both the chlorination regime and small variations in CPO concentration at very low levels can significantly alter community composition.

In addition to developing information on the effects of chlorination, this research provided an opportunity to evaluate the long-term open microcosm technique as an ecological assessment tool. The methodology was successful but required rigorous experimental design, construction, and statistical procedures for useful interpretation.

A stream microcosm methodology is under development in a project with Oregon State University (RP2046-1). Studying the biologic effects of toxic substances in streams is complicated by the procedural difficulties of conducting experiments in running water. Most current research efforts on the aquatic effects of toxic substances focus on lakes and use static microcosms. Results from such studies cannot be applied directly to streams because of the differences in the kinetics of a given substance in flowing water. The successful development of artificial streams would provide a valuable predictive tool for studies of toxic substances.

This work, scheduled for completion early next year, is expected to produce both a facility for specific research projects and a research protocol for studying fundamental ecological processes. The results will also include an assessment of the inadequacies of simple bioassays for predicting the behavior and effects of toxic substances in streams.

In RP2368-1 the Ecosystems Research Center of Cornell University is conducting laboratory and field toxicity studies to determine if bioassays can accurately predict the effects of a model toxicant (cadmium) on fish in ponds. Through laboratory bioassays the researchers are establishing the concentration of cadmium that will kill 50% of the test population in 96 hours (a measure of lethal concentration called the 96-hour LC_{50}). Fathead minnows obtained from stock cultures make up the test population; this fish was selected because it is commonly used by EPA in laboratory bioassays.

For their bioassays the Cornell researchers are using laboratory water, water collected from the experimental ponds, or water and sediments collected from the ponds. The initial cadmium concentration in the bioassays ranges from approximately 100 to

5000 μg/L. Ten to 20 fish are added to each aquarium. Cadmium concentrations and basic limnological parameters are monitored daily.

The field experiments are designed to replicate the laboratory bioassays in an environment that is subject to daily variations in chemical and biotic parameters typical of natural pond ecosystems. As in the laboratory experiments, a fixed quantity of cadmium is added to the water and its effects on fish mortality are determined. The effects of cadmium on the fecundity of the minnows will be estimated by comparing the number of eggs per female as a function of the time spent in treated and untreated ponds.

Terrestrial microcosms

In RP1224-5 Battelle, Columbus Laboratories developed an agricultural microcosm methodology for assessing the ecological effects of utility wastes (EA-2364). As a test case, the project examined the effects of fly ash deposition.

The microcosms used soil cores from an agricultural field; results from the microcosms were compared with those from plots in the same field. The microcosm and field plots were planted with an alfalfa-clover crop. After the crop was established, fly ash collected from the stack of a power plant was applied as simulated airborne deposition to the microcosms and field plots at rates of 5, 9, and 27 t/ha. The researchers then studied the effects on three major parameters: crop yield (productivity), nutrient stripping (loss in soil water), and trace element fate (uptake in plant tissues).

The crop yields of both the laboratory microcosms and the field plots were within the range for farm yields reported by local agronomists. None of the three levels of fly ash treatment significantly affected yields of the microcosms or the field plots. According to the net primary productivity data, differences in yield between the two types of experimental unit were not significant.

Nutrient loss in microcosm leachate and field plot soil water was measured to evaluate the extent of ecosystem disruption caused by the different fly ash treatments. Increased nitrate-nitrogen loss was observed, although no effects on primary productivity were detected. Increased nitrate-nitrogen loss could eventually lead to declines in primary productivity.

Plant uptake of 16 trace elements was monitored. At the highest fly ash treatment level, both plants from the microcosms and plants from the field plots showed statistically significant higher concentrations for three elements—arsenic, selenium, and chromium—as compared with control plants. Nickel and strontium concentrations were significantly higher in plants from the microcosms but not in plants from the field plots. In general, however, the microcosms successfully predicted the uptake of trace elements by the field-grown crops.

In RP1632 the Tennessee Valley Authority studied the effects of simulated acidic precipitation on forest microcosms. Microcosms consisting of a restructured forest soil profile and seedlings of tulip poplar, white oak, and Virginia pine were treated for 30 months with precipitation in a way that simulated field conditions as closely as possible while excluding naturally occurring precipitation. A synthetic precipitation solution was adjusted with a mixture of sulfuric acid (70%) and nitric acid (30%) to produce simulated precipitation treatments with annual average pH values of 5.7, 4.5, 4.0, and 3.5. The researchers evaluated the impact of these treatments on foliar leaching and plant nutrient content, soil nutrient leaching, the decomposition of organic matter in litter and mineral soil, and plant physiological and morphological responses.

Throughfall pH responded significantly to pH treatment. This indicates that while there was some neutralizing capacity in the canopy, it was not sufficient to completely counteract the treatments applied. Throughfall nitrate and sulfate levels responded significantly to increased acidity but in different patterns. Throughfall nitrate concentration and input to the soil declined over time, whereas sulfate concentration and input increased with time.

Although throughfall analysis suggested that the leaching of certain elements increased with greater acidity, foliage analysis failed to indicate any consistently significant change in any element for the three tree species studied. Likewise, the analysis of stem and root tissue failed to show any significant treatment effects.

Soil analysis indicated statistically significant lower concentrations of exchangeable calcium and magnesium in the top 3.5 cm of the mineral soil after 30 months of pH 3.5 treatment. With this treatment the concentration of exchangeable calcium was also lower at depths of 3.5 to 20 cm in the mineral soil.

At the bottom of the soil profile (100 cm), no significant effect on the concentration of any nutrient was observed. The concentration data for this depth indicate that cations mobilized out of the surface soil horizons as a result of treatment were immobilized before reaching the bottom of the profile. An evaluation of nutrient flux out of the microcosms at the 100-cm depth did not indicate any statistically significant response to the pH 3.5 treatment.

Carbon dioxide evolution was used as an index of decomposer activity. The microcosm measurements revealed no statistically significant effect of treatment on decomposition.

As for plant response, there were differences in diameter growth rate but no statistical evidence that any of these differences were due to treatment. Likewise, there was no indication that treatment affected bud break, leaf senescence, chlorophyll content, stomatal size, stomatal density, or rates of photosynthesis, respiration, and transpiration. There was no visible indication of foliar injury; nor were there any discernible differences in cuticle density or cuticular detail that could be related to treatment.

Finally, it is important to note that the concentration and flux values observed in this study are consistent with published values from field and other microcosm studies. This lends support to the thesis that the microcosm is a valid surrogate for the field system. *Project Manager: John Huckabee*

RISK ASSESSMENT OF AMBIENT SO_2 AND PARTICULATE MATTER

Analytic strategies for developing health-based environmental regulations are undergoing change. In the past regulations were designed so that there would be zero risk to all significant segments of the population. There appears to be a growing realization of the problem of attaining zero risk at a reasonable cost. This realization has resulted in the consideration of alternative strategies. One new strategy for developing regulations calls for assessing the health risks associated with various levels of pollution and setting standards at levels that provide reasonable protection to the general public. Standards based on this risk assessment approach are far more defensible from both a scientific and a cost-benefit standpoint than those based on a zero-risk approach. Several environmental bills currently before Congress call for the use of risk assessment in developing health-based environmental standards. Under RP1954 EPRI is sponsoring a study with Roth Associates, Inc., to develop and illustrate methods of estimating the health risks associated with ambient levels of sulfur dioxide (SO_2) and particulate matter.

Risk assessment methodology

Risk assessment is the process of estimating the probability or incidence of a health effect associated with a specified ambient level of a pollutant under a particular environmental condition. The risk can be stated as the probability that a randomly chosen individual would experience a health effect or as the expected number of health effects in the population under study.

Figure 1 illustrates the general steps involved in performing a risk assessment. The first step is to identify and characterize the population at risk—that is, the group of individuals who are sensitive to the ambient level of the pollutant of interest and thus are most likely to be affected by the pollutant. Then dose-response curves are developed on the basis of health effects data; these curves estimate the association between exposure level and probability of health effect. The next step is to develop exposure profiles, which estimate the ambient air quality of various environments where individuals spend their time, estimate time budgets for individuals over the various environments, and combine this information to estimate a person's exposure over time and over environments. Then the health, exposure, and population data are integrated to yield risk estimates.

Ambient pollution frequently affects only segments of the population. For example, individuals sensitive to ambient SO_2 levels may include asthmatics engaged in exercise. Demographic data on sensitive populations are now available for the major standard metropolitan statistical areas (SMSAs) in the United States. For the EPRI project, survey data on asthmatics were obtained from the National Center for Health Statistics and were analyzed to determine the size and makeup of this sensitive population by race, sex, age, and geographic location.

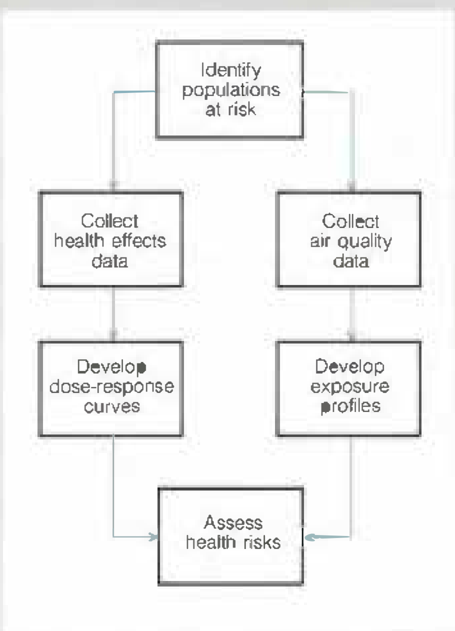


Figure 1 Steps in risk assessment for developing health-based environmental regulations. First the populations at risk are identified. Then health effects data from animal toxicologic, human clinical, and epidemiologic studies are used in developing dose-response curves for the substance of interest, and data on ambient air quality and emissions are used in developing population exposure profiles. Finally, the data are integrated to arrive at risk estimates.

Health effects data can be obtained from three types of studies: animal toxicologic, human clinical, and epidemiologic. The RP1954 researchers have examined and compared a number of key SO_2 human clinical studies in order to develop dose-response curves. They have found that the SO_2 levels at which effects occur are not well established. In some studies there were no effects for 15-minute exposures even at SO_2 levels as high as 1.0 ppm; in other studies effects were observed at levels as low as 0.25 ppm. (Attempts to reconcile these differences are under way. Responses to the lowest level may reflect how exposure was administered; or the differences may reflect other variables, such as temperature and humidity.) Further work in comparing results from SO_2 human clinical studies with those from epidemiologic and animal toxicologic studies is expected to define a dose-response curve that best fits the available health data.

The next step in calculating the risk associated with SO_2 or particulate matter is to determine the general population's exposure to these pollutants in indoor and outdoor environments. This calculation requires information on pollution levels in indoor and outdoor environments and the time spent by the general population in each environment.

Indoor and outdoor pollution levels can be either measured directly or estimated from emissions data by using models. For SO_2 two tasks are being undertaken to characterize short-term ambient levels: an analysis of EPA's national ambient monitoring data base and the modeling of SO_2 levels in study areas where high ambient levels are likely.

Time budget data came from EPA's NEM (NAAQS Exposure Model) program. These data give probabilities that individuals are indoors and outdoors by day of week and time of day for different age-occupation subgroups of the population in selected cities. They also include probabilities on whether individuals are engaged in heavy, moderate, or no exercise. This is important in the SO_2 case because (as stated above) current ambient SO_2 levels appear to affect exercising asthmatics.

There are several problems with the NEM data, which EPRI is in the process of correcting. For example, the data currently contain no adjustments for variables such as season and weather. This is critical because, in general, people spend more time outdoors on warm, clear days than on cold, rainy ones. Also, there are indications that some of the exposure model data are of poor quality. Moreover, the data reflect the activities of the general population rather than those of sensitive subgroups.

Finally, health data, exposure data, and population data are integrated to determine the risks associated with a particular exposure level. The EPRI methodology and data base have been used in two case studies. The Utility Air Regulatory Group (UARG) funded and performed a risk assessment on short-term SO_2 exposures around two large rural power plants that are essentially responsible for ambient SO_2 concentrations; and Consolidated Edison Co. of New York initiated a risk assessment for New York City, where ambient SO_2 concentrations are attributable to both major sources and thousands of low-level emitters. The strategies and results of these risk assessments are described next.

Rural power plant analysis

The two rural power plants examined by UARG are two of the largest SO_2-emitting plants in the United States. For the analysis the area around each plant was divided into 180 sectors by using a polar coordinate grid. Sector boundaries were marked by concentric circles roughly 3, 7, 15, 25, and 35 mi (5, 11, 24, 40, and 56 km) from each plant and by radials spaced at 10° intervals.

The EPA-approved CRSTER model was used to predict SO_2 concentrations for the center of each grid sector for every hour of the year. On-site meteorologic data for one year and stack and emission parameters appropriate to each plant were used in these computations. For one of the plants, actual hour-by-hour load data were available for the same period as the meteorologic data and were used to calculate hourly emission rates and stack velocities. At the second plant, for which hourly load data were not available, the analysis was conservatively based on continuous full-load operation during the entire year.

Because EPA has identified a range of 0.5–0.75 ppm for a new one-hour SO_2 primary standard, a concentration of 0.5 ppm was used in this analysis to define a dose-response curve. This curve is simply a step function that assumes no effects below 0.5 ppm and 100% response above 0.5 ppm. The CRSTER dispersion model was used to identify the sectors and hours for which predicted hourly SO_2 levels equaled or exceeded 0.5 ppm. In the populated sectors near the first plant, there were a total of 5 sector-hours per year when the SO_2 level was ≥0.5 ppm; for the second plant, there were 18 sector-hours. All these sector-hours occurred within 7.5 mi (12 km) of plant 1 and within 6.5 mi (10.5 km) of plant 2.

The number of asthmatics in each of the sectors that might experience one or more hourly SO_2 concentrations above 0.5 ppm was calculated by multiplying the sector's population by the asthma prevalence rate (adjusted for age, sex, and race) for the geographic region in which the plant is located. The population data came from the 1980 data tapes of the U.S. Bureau of the Census, and the asthma prevalence rates were based on data from the National Center for Health Statistics. There were estimated to be 418 asthmatics living within 7.5 mi of plant 1 and 139 asthmatics within 6.5 mi of plant 2.

The next step in the analysis was to estimate the probability that asthmatics living in the sectors of interest were engaged in outdoor exercise during times when the hourly SO_2 level was ≥0.5 ppm. These probabilities were based on data in a document prepared for EPA by Pedco Environmental, Inc., entitled "NAAQS Exposure Model (NEM) and Its Application to Particulate Matter" (August 31, 1981).

The number of hours during which asthmatics were exercising outdoors and SO_2 equaled or exceeded 0.5 ppm was then determined for each plant. These hours, called coincidence hours, were calculated by multiplying the number of asthmatics by the exercising probability for each sector-hour with an SO_2 level of ≥0.5 ppm and then adding the products. The results from the power plant analyses are summarized in Table 1, which shows that there were on average 3 coincidence hours in a year for plant 1 and 12 hours for plant 2.

These results can be used to determine the probability that a randomly chosen asthmatic will be exercising in a sector where the SO_2 concentration is ≥0.5 ppm. To do so, the number of annual coincidence hours is divided by the number of annual asthmatic-hours (i.e., the number of asthmatics near the plant times the number of hours in a year). This calculation yields a probability of 1 in 1.2 million for the first power plant and 1 in 100,000 for the second plant. If these probabilities are projected to the general population, the probability that a randomly chosen person is an exercising asthmatic exposed to more than 0.5 ppm SO_2 in a given hour is a factor of 35 to 40 less than the values cited above.

Table 1
RESULTS FROM RURAL POWER PLANT RISK ANALYSIS

	Power Plant 1	Power Plant 2
Asthmatics near plant*	418	139
Populated sectors with $SO_2 \geq 0.5$ ppm	3	4
Annual populated sector-hours with $SO_2 \geq 0.5$ ppm	5	18
Annual coincidence hours (exercising asthmatics, $SO_2 \geq 0.5$ ppm)	3	12

*Within 7.5 mi (12 km) of plant 1; within 6.5 mi (10.5 km) of plant 2.

Urban analysis

The monitoring of SO_2 levels in New York City indicated no hours when SO_2 exceeded 0.25 ppm. Thus, at present pollution levels there should be no risk to exercising asthmatics. Because seven electric generating units in the metropolitan area have been proposed as coal conversion candidates, however, the Con Edison analysis added the projected impact of emissions from these units to the monitored SO_2 background levels; it also considered the impact of a total of five new generating units proposed for construction at the coal conversion candidate plants.

The methodology for the New York analysis was similar to the one used in the rural power plant study. Manhattan and other areas of relatively high SO_2 levels—the southern portion of the Bronx, western Queens, and a portion of northern Brooklyn—were divided by a rectangular coordinate grid system into sectors 1 km square. Sectors 2 km square were used for Staten Island and the rest of the Bronx, Queens, and Brooklyn, where SO_2 levels are relatively low.

SO_2 values were estimated for receptors at the center of each grid sector for every hour of the year by adding together (1) the impact on ambient air quality of continuous maximum load operation of the 12 generating units described above and (2) the concurrent hourly SO_2 concentrations measured at 13 monitoring sites within or near the study area. Hourly estimates of the impact of the 12 units were made by using the EPA CRSTER model in the urban or rural mode, depending on the characteristics of the area immediately surrounding each plant. For each unit an additional calculation was made for several receptors along the plume centerline (the calculated locus of maximum concentrations) for the hour with the highest SO_2 estimates at grid coordinates. This ensured that maximum hourly concentrations were not missed.

In New York the calculated SO_2 concentrations did not approach the 0.5-ppm level of interest. The highest calculated hourly SO_2 level in the city was about 0.26 ppm, and this occurred in a Staten Island park within a 200-meter-square area that had no access road. It can be seen from these calculations that the coincidence of ambient SO_2 concentrations greater than 0.25 ppm and asthmatics exercising outdoors in New York City is virtually zero.

Although the New York City analysis indicates zero risk to the exercising asthmatic from SO_2 exposure equaling or exceeding 0.5 ppm, this analysis cannot be generalized to all cities, a few of which have reported ambient SO_2 concentrations above 0.5 ppm. More urban risk assessments are planned to bound the risk to asthmatics of SO_2 in urban areas. Current EPRI plans include the development of improved data inputs and precise estimates of urban exposure to SO_2 and particulates. After these are illustrated by EPRI, UARG may use them in analyses.

Further efforts

EPRI is sponsoring research to complete the RP1954 assessment of the risk associated with short-term SO_2 exposures. This involves selecting candidate SMSAs, developing additional dose-response curves from health effects data, and examining the exposure models for accuracy and applicability. Risk assessments for daily (as opposed to hourly) SO_2 exposures and for daily particulate matter exposures are also planned.

It will be more difficult to perform particulate matter risk assessments for two reasons. First, unlike SO_2, this pollutant is of concern indoors as well as outdoors. As a result, a more complex model will have to be developed to characterize exposures. Second, particulate matter varies by species according to geographic location; thus it is questionable whether risk findings from specific sites can be generalized.

Researchers will also integrate the results on SO_2 and particulate matter because some evidence suggests there are synergistic effects associated with joint exposures. New models will have to be developed to address this issue. *Technical Manager: Ronald E. Wyzga*

R&D Status Report
ENERGY MANAGEMENT AND UTILIZATION DIVISION

Fritz Kalhammer, Vice President

EMPS DEVELOPMENT AND VALIDATION

EMPS (EPRI methodology for preferred systems) is a computer program that simulates the hour-by-hour electricity demand and consumption of residential buildings. It is a powerful tool for investigating the performance of residential energy systems and their likely impact on utilities and customers. Originally designed to evaluate active solar systems for residential buildings, EMPS has matured into a comprehensive methodology that can be applied to passive solar and conventional energy systems as well. A significant advantage EMPS has over other currently available models is its broad range of capabilities for simulating residential HVAC (heating, ventilating, and air conditioning) and water-heating equipment. As part of the EMPS development effort, EPRI has sponsored several validation studies comparing the program's calculations with field measurements. These comparisons have added to our understanding of the physical processes that determine residential building energy use, have led to the improvement and expansion of EMPS, and have fostered utility confidence in its value as an analytic and design tool.

The latest version of EMPS (EMPS 2.1) is a set of three computer programs that describe the electricity demand and consumption of residential buildings. Although these programs work together, they may be run separately (i.e., in a stand-alone mode). The three programs have the following capabilities.

▫ The EMPS energy analysis program uses information on building characteristics and occupancy, HVAC system data, appliance use schedules, and EMPS-compatible weather data to determine a building's hour-by-hour electric energy consumption.

▫ The EMPS economic program uses results from the energy analysis program to determine the cost to the homeowner of energy consumption (according to a rate analysis), the cost to the utility of supplying the energy (according to a cost-of-service analysis), and a life-cycle cost for owning and operating the equipment.

▫ The EMPS weather tape conversion program creates EMPS-compatible weather tapes from TMY, SOLMET, or user-prepared weather data files.

Table 1 lists the capabilities and features of the EMPS energy analysis program. Its flexibility regarding input on building configuration, thermal properties, and heating and cooling systems allows the program to model standard single- and multilevel residential designs. These designs include single-family attached and detached residences constructed on slabs or with basement foundations or crawl spaces. Users may specify a mix of room and central HVAC distribution systems in order to model various retrofit situations, such as the addition of a room onto an existing structure.

The energy analysis program offers several options in evaluating the projected performance of building designs and equipment. For example, the program can compare the demand and energy use of conventional and alternative (including high-efficiency, solar, ground-coupled, and heat recovery) HVAC systems and domestic water-heating systems. Similarly, it can compare central heat pump systems with baseboard heating or room air conditioning systems. It can also evaluate how the sizing of heating and cooling equipment affects performance and how passive solar design options affect building heating and cooling thermal loads, electric energy use patterns, and comfort conditions. The user selects the energy analyses desired for a specific application at the time EMPS is run. Thus, if the performance of a residential water heater is being investigated, the user can request that EMPS eliminate calculations relating to the rest of the building.

The economic analysis program is available as a postprocessor to the energy analysis program. For the building and conditions specified in the energy analysis, this program assesses the cost to the customer of owning and operating the equipment and the cost to the utility of supplying the required energy.

EMPS development

In 1975 EPRI contracted with Arthur D. Little, Inc., to develop a computer program for use in defining the potential impacts of active solar heating and cooling systems on utilities (RP549-1). This program, the predecessor of EMPS, was called EMPSS—EPRI methodology for preferred solar systems. After further work to refine the program (RP926), EMPSS was released in 1978. Since then, some 20 EPRI member utilities have used it to examine solar space-conditioning and water-heating system designs.

In 1981, responding to utility interest in passive solar designs, EPRI initiated another project with Arthur D. Little to modify the EMPSS program to enable the prediction of energy use patterns in passive solar homes (RP1830-4). The resulting program, called EMPS 2.0, provided extensive capabilities for analyzing passive solar system designs and for evaluating energy demand patterns in conventionally designed residences. Approximately 15 utilities tested EMPS 2.0 during 1981–1983, and interest in the program has led to the formation of an active users group.

In 1983 EMPS was further refined. Many of its algorithms were improved, part of the

Table 1
EMPS ENERGY ANALYSIS PROGRAM CAPABILITIES

Analysis Category	Capabilities/Features
Building thermal loads	
Building configuration	1–10 thermally coupled spaces
Construction parameters	User-defined or selected from library
Building foundation	Basement, crawl space, slab
Air exchange	Infiltration, natural ventilation, mechanical ventilation (room or through the house)
Passive solar design	
Solar gain	Detailed ray trace with internal scatter
Storage walls	Trombe and water walls
Shading	Building self-shading
HVAC system	
Heating equipment	Electric furnace, baseboard electric, conventional air-to-air heat pump, two-stage heat pump, ground-coupled heat pump
Cooling equipment	Conventional air-to-air heat pump, two-stage heat pump, ground-coupled heat pump, room dehumidifier, ceiling fan
Control technique	Thermostat schedules, utility-controlled load shedding
Distribution system	Unitary (room) and/or central for heating and cooling equipment
Water-heating system	
Conventional unit	Two elements with interlock and time control
Solar	One- or two-tank design
Heat recovery	Air conditioner and heat pump desuperheat recovery
High efficiency	Dedicated heat pump

EMPSS active solar system model was incorporated, and an economic analysis section was added. The resulting program, EMPS 2.1, was released for general use in June 1984.

EMPS validation

As EMPS has evolved, validation studies using field measurements have been important in establishing the program's simulation capabilities and in identifying its limitations. One study on the performance of load-managed water heaters focused on EMPS algorithms for individual system components. Other validations have considered overall building energy use. Although the results of validations involving entire buildings are less definitive than single-component validations (because of the possibility of mutually compensating errors), such studies are valuable in that they reflect a common use of the program. Testing of EMPS 2.1 to date has consisted of four partial validations—two completed, two in progress—and a comparison of EMPS results with those of another computer program, DOE-2.

RP549-3 examined load-managed solar water-heating systems in one solar test home on Long Island, New York, and two test homes in Albuquerque, New Mexico (*EPRI Journal*, July/August 1983, p. 54). As part of this project, which was sponsored by EPRI, Public Service Co. of New Mexico, and Long Island Lighting Co., data from the houses were compared with performance predictions by EMPS. For this validation the original generalized EMPS water heater model was expanded into a much more comprehensive model capable of simulating the specific hardware being tested. Agreement between experimental data and EMPS predictions of the water heaters' hourly energy use was good (within about 10% root-mean-square error). EMPS was subsequently used to simulate a number of water heater configurations not represented in the test houses.

The algorithms used in the EMPS thermal load, electric furnace, heat pump, air conditioner, duct loss, and infiltration models were validated by comparing model predictions with data developed by Ohio State University in an earlier EPRI project (RP137-1). The data came from an extensively monitored (unoccupied) house in Columbus, Ohio, equipped with an electric furnace and central air conditioning. As shown in Figure 1 for the heating season, daily and hourly EMPS predictions accurately reflected the magnitude and patterns of the house's actual energy use. There was also good agreement between predictions and field data for the cooling season.

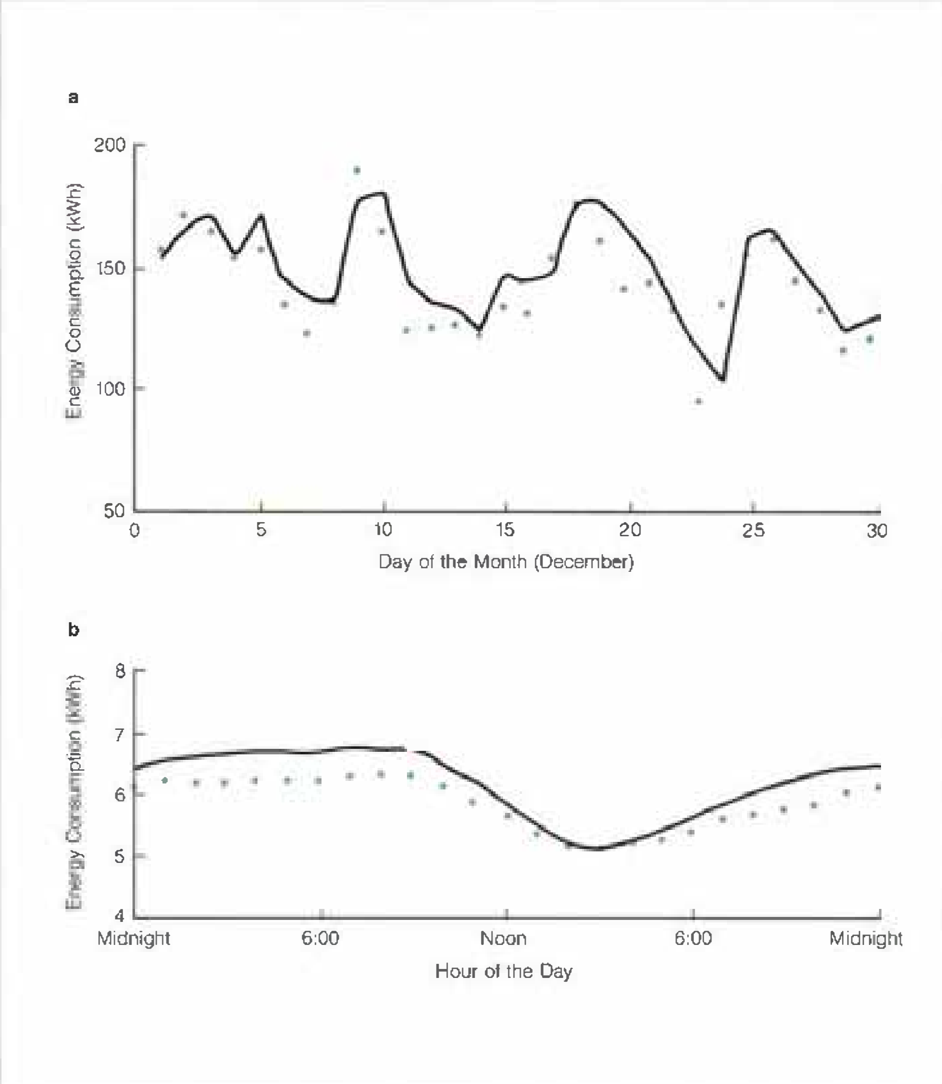
In the third validation study—being performed as part of a contract with Geomet Technologies, Inc. (RP2034-1)—EMPS calculations of building space temperatures, HVAC energy use, infiltration, and ventilation are being compared with data from an experimental house and control house in Washington, D.C. The results of this comparison, although preliminary, are quite promising. For example, in one four-day period, differences between measured and EMPS-predicted energy use were less than 3%.

The fourth validation study is part of work by the National Bureau of Standards investigating how partitions and thermal mass in residential buildings affect utility load profiles (RP2034-7). This study is using data from a DOE-sponsored project on the thermal performance of six test houses. Heating and cooling loads measured in these test buildings are being compared with values predicted by EMPS. Once the validation is completed, EMPS will be used to estimate peak demand and annual heating and cooling energy consumption for typical residential building configurations in four other U.S. regions. It is hoped that in this way EMPS will enable the findings of the study to be generalized beyond the experimental region.

Instead of comparing EMPS predictions with experimental data, an independent study by the Tennessee Valley Authority has compared the results from an EMPS simulation with results generated by DOE-2, an energy analysis computer program widely used by utilities. Both programs were used to predict thermal loads, energy consumption, and space temperatures for a hypothetical occupied house in Chattanooga, Tennessee.

The two programs' estimates of kWh use

Figure 1 EMPS predictions (colored points) and field measurements from a test house (curves) for (a) daily energy consumption during the heating season and (b) hourly energy consumption during the average heating-season day. Results from this and other validation efforts have demonstrated the accuracy of EMPS, a computer program for evaluating the performance and impacts of residential energy systems.



during the heating season differed by less than 5%, and virtually identical daily and annual heating energy demand patterns were predicted. Cooling-season kWh estimates were also in close agreement, differing by less than 3%. However, the daily and annual cooling energy demand patterns predicted by the two programs varied significantly. A revised thermal balance algorithm has been incorporated into EMPS and has reduced these differences.

In addition to these efforts, various utilities are conducting independent validations of EMPS. Information on the use of EMPS is exchanged through the utility users group, which meets twice a year. *Project Manager: Gary Purcell*

SURVEY OF UTILITY END-USE PROJECTS

Electric utility involvement in end-use activities has increased in recent years. Utilities are becoming more involved in this area for several reasons—to explore the potential for deferring generating capacity expenditures, to improve system reliability and economics, to comply with regulatory requirements, and to meet customer needs. The diversity of these objectives has led utilities to implement projects featuring a wide variety of end-use technologies. Since 1977 EPRI has sponsored periodic surveys of utility projects related to demand-side management. The main goal of the surveys is to consolidate technical information from these projects and to present it in a format useful both to the utility industry and to EPRI in its end-use R&D planning. The results of the latest survey, conducted in 1983 under RP1940-8, are now available from Research Reports Center (EPRI EM-3529).

Survey scope and methodology

The 1983 survey covers utility efforts in three broad areas: load management, conservation, and solar. It differs from previous surveys in that it includes more types of end-use activity and is limited to projects directly involving utility customers.

Load management is divided into two major categories: load control projects and projects on thermal energy storage and dual-fuel heating. In load control projects the normal usage patterns of end-use appliances or other electrical devices are deliberately modified to produce an overall change in the customer's and/or the utility's load profile. The survey covers direct, distributed, and local load control. (In contrast to direct control, distributed and local control techniques incorporate point-of-use data into control decisions; distributed control includes a utility communication link.)

Thermal energy storage and dual-fuel heating are technologies that reduce or eliminate peak-period electricity demand without altering customer comfort levels. Thermal energy storage systems use electricity to store heat or coolness in a reservoir during utility off-peak hours for later use during peak hours, thereby shifting the load. Dual-fuel heating systems switch from electric operation to backup fuel (generally oil or liquefied petroleum gas) during peak periods, thereby eliminating the load entirely. Survey coverage of these technologies, as well as of load control, is comprehensive: all known utility activities are reported.

Several activities promoting efficient energy use were surveyed for the first time in 1983. The area of conservation was expanded to accommodate this change. The activities surveyed fall into four major categories: thermal performance improvement, high-efficiency equipment, modification of energy use patterns, and conservation services and information. Because nearly every electric utility in the United States conducts efforts to promote the efficient use of energy, survey coverage in this area is representative rather than comprehensive.

In 1980 the survey began to document a wide range of utility solar activities. The 1983 survey narrows this range to focus on activities directly involving the end user. Within these revised bounds, coverage is comprehensive.

The 1983 survey involved a multistage data collection process aimed at identifying new projects and updating information on the 871 projects reported in the 1981 survey (EM-2649, Volume 1). Survey personnel identified new projects by contacting various equipment manufacturers and representatives of utility organizations, by reviewing industry trade journals and newsletters, and by canvassing utilities through a broad-based mail inquiry. Telephone interviews were conducted as necessary to clarify mail responses and to follow up on nonresponding utilities.

Survey findings

The 1983 survey identified 953 end-use projects sponsored by 298 electric utilities. These projects represent over 5 million customer installations, 98% of which involve load control or efficient energy use (Table 2).

The survey shows significant activity in each of seven U.S. regions covering the 48 conterminous states (Table 3). Municipal, investor-owned, and rural distribution cooperative utilities reported 90% of this activity, with the remaining 10% reported by federal, state, and district utilities and generation and transmission utilities.

The reported projects have also been divided into two categories by scope. The first covers test, demonstration, and monitoring projects, which evaluate the feasibility, effectiveness, or acceptability of concepts and technologies. The second category covers implementation activities, which promote specific technologies and techniques available to customers on a broad basis. Of the 953 projects, 523 are implementation activities. Of these, nearly 78% involve load control or efficient energy use; the remaining 22% are evenly divided between end-use solar projects and projects on thermal energy storage and dual-fuel heating. The 430 projects in the test, demonstration, and monitoring category break down as follows: end-use solar, 44%; efficient energy use, 24%; thermal storage and dual-fuel heating, 19%; and load control, 13%.

Since the 1981 survey, the number of projects on efficient energy use has increased by 70%, from 207 to 351; projects on thermal storage and dual-fuel heating have increased by 50%, from 91 to 137; and load control projects have increased by 4%, from 210 to 218. The number of end-use solar projects has declined 32%, from 363 to 247. Although some changes are attributable to revisions in reporting criteria and to improved surveying methods, the survey results indicate continued real growth in utility end-use activities.

Table 2
1983 SURVEY RESULTS ON UTILITY END-USE ACTIVITIES

Activity	Number of Projects	Number of Installations
Load control	218	
Water heaters		648,437
Air conditioners		515,252
Swimming pool pumps		258,993
Space-heating systems		50,238
Irrigation pumps		14,261
Miscellaneous		13,710
Thermal storage/dual-fuel heating	137	
Dual-fuel heating		19,885
Storage water heating		6,992
Storage space heating		5,290
Storage air conditioning		232
Combination storage		40
Efficient energy use	351	
Thermal performance improvement		2,095,895
High-efficiency equipment		1,415,698
Use pattern modification		4,914
Conservation services/information		—
End-use solar	247	
Water heating		79,790
Passive space heating/cooling		623
Active space heating		160
Active space cooling		13
Total	953	5,130,423

Table 3
UTILITY END-USE PROJECTS BY REGION AND TYPE

Region	Load Control	Thermal Storage/Dual-Fuel Heating	Efficient Energy Use	End-Use Solar
Northeast	22	32	78	41
East Central	8	14	25	20
Southeast	74	22	71	41
West Central	56	53	31	39
South Central	31	7	50	27
Northwest	2	1	48	36
West	25	8	48	43

Many utilities provide customer incentives in conjunction with their end-use projects. The survey details these incentives, which vary widely with technology and utility-specific objectives. They include zero- or low-interest loans, grants, customer or dealer rebates, special electricity rates, free installation and/or materials, and awards to customers meeting certain standards.

Many utilities provided information on the load impacts of projects (in terms of peak kW reduction or average annual kWh reduction). A sampling of these results follows.

- Reported load control projects reduced utility peak demand by 0.34–1.5 kW per controlled residential air conditioner, 0.39–1.36 kW per controlled residential water heater in winter, and 0.22–1.2 kW per controlled residential water heater in summer.

- Thermal energy storage reduced peak demand by 6.7–9.6 kW per space-heating installation and 0.7–1.1 kW per water-heating installation. Dual-fuel heating reduced peak demand by 7.1–10 kW per installation.

- Projects on efficient energy use produced significant kWh savings. Thermal performance improvement activities yielded annual savings of 10–60% for retrofit weatherization, 25–30% for new building weatherization, 10–15% for ceiling insulation, and 35–40% for window treatment. Energy savings associated with water heater wraps were generally in the range of 400–600 kWh/yr. High-efficiency equipment (e.g., air-source heat pumps, heat recovery water heaters) resulted in savings of 21–55%.

- End-use solar projects also produced significant energy savings. In many cases the solar contribution (the fraction of the load met by solar energy) was reported. For domestic water heating, annual contributions ranged from 14 to 80% for active systems and from 20 to 30% for passive systems. For space-conditioning systems, reported solar contributions were 15–65% for active heating, 35–65% for active cooling, and 20–100% for passive heating and cooling (primarily heating). Energy savings for swimming pool heating ranged from 3500 to 20,000 kWh/yr per installation.

Related EPRI efforts

Many of the projects identified by this and previous surveys have begun to yield results and conclusions. In 1983 EPRI initiated a major effort to collect, consolidate, and interpret these findings. The resulting in-depth technology reviews, to be published separately from the surveys, will assess the effectiveness of the technologies in meeting their original objectives; analyze the data for trends and correlations to enable generalization; and identify information gaps and recommend directions for the development, field testing, and use of the technologies.

The data, collected primarily in on-site interviews, will cover technology capabilities, performance, costs, load characteristics, and other pertinent field experience. The information will be stored in a computerized data base with remote access for data input, retrieval, and evaluation.

The first of the technology reviews (RP1940-6), which is nearly completed, addresses load management. It is broad in scope, covering all tested or implemented technologies. The researchers have compiled a wealth of data, sufficient in some cases to reveal consistent trends. They have also discovered a serious lack of data in other areas, particularly distributed and local load control.

Another technology review (RP1940-10) was recently initiated for residential conservation and efficient energy use technologies and programs. Similar work is planned to address direct load control protocols and the reliability and maintainability of direct control switches. Also, starting next year, selected end-use technologies in the commercial building sector will be reviewed. Joint projects with utilities will be undertaken as necessary to fill data gaps.

As well as being reported in EM-3529, the data from the 1983 survey are available in computerized form. This data base, which can be easily accessed via telephone and a remote terminal or microcomputer, is useful for those wishing to organize the information in a different way or to conduct further analyses. For more information on this service, call the EPRI Technical Information Center (415-855-2411) and refer to the Utility End-Use Projects Data Base. *Project Manager: Veronika A. Rabl*

R&D Status Report
NUCLEAR POWER DIVISION

John J. Taylor, Vice President

KINETIC BONDING OF CONDENSER TUBE JOINTS

*A new process, developed under EPRI sponsorship, makes leak-tight condenser joints by using a kinetic bonding (explosive welding) procedure. "The New Bond" (*EPRI Journal*, December 1982, pp. 20–25) reported on the laboratory success of the process. Since that time a major effort has been made to commercialize the bonding procedure for eventual use in condenser service.*

The driving force behind the kinetic bonding project conducted by Lockheed Missiles and Space Co. was a badly needed improvement in reactor water chemistry (RP1333-1). Condensers have been a principal source of reactor water contamination, allowing impure cooling water from the ocean, river, or lake to leak into the reactor through failed condenser tubes or tube-to-tubesheet joints. The commonly used rolled-joint process and even the fusion-welded procedure did not provide the needed joint integrity.

The new kinetic bonding process involves inserting a small plastic package containing an explosive into the end of each condenser tube before it is joined to the tubesheet. Detonating the explosive drives the tube wall at very high speed in a radial direction against the inside surface of the tubesheet hole, forming a strong metallurgical bond. The initiation system, composed of explosive in a plastic rail, can detonate up to 1000 shots sequentially, minimizing operational cost and time. Successful laboratory tests had demonstrated multiple firing of up to 100 tubes, but field application had not yet been made.

The steps considered necessary to carry the process through the commercialization phase included demonstration of the process in a small prototype tube bundle, further progress in tooling development to speed up the manufacture of the explosive packages, and transfer of the technology to a licensee who could provide the welding service to the utilities. These tasks were undertaken simultaneously.

Although the project had developed first-generation tooling to prove that semiautomatic manufacture of the explosive packages is feasible, the production time was not the best possible. The step that required the most time involved pressing the main charge of nitroguanidine into the plastic cup. The loading unit was therefore redesigned to load the entire charge at one time instead of in several increments. This decreased the time required for this step by a factor of three and also improved the charge density distribution. Although high-speed production of large numbers of explosive packages and further unit cost reduction will require more changes to the final tooling, the recent changes permit reasonable production for early field application.

As recognized at the beginning of the project, a major key to commercialization was obtaining a licensee who could provide the kinetic bonding service to the utilities. A licensee agreement was signed with Foster Wheeler Energy Corp. in the fall of 1983. Foster Wheeler has had extensive experience with explosives in manufacturing and in repair. As a manufacturer of large power plant condensers, it has worked for many years with the utility industry. Its in-reactor experience includes having used an explosive technique for the recent repair of 31,000 tubes in the Three Mile Island-1 steam generators. Another important factor in its selection was the enthusiastic support of its corporate management, who saw the kinetic bonding process as a natural extension of and complement to the corporation's existing activities.

The technology transfer to Foster Wheeler personnel was initiated immediately after an agreement was signed. Technical staff from Foster Wheeler spent several weeks at Lockheed's Santa Cruz, California, facility, learning the details of the process and how to use the tooling for the manufacturing process. Foster Wheeler then purchased the tooling for making both the explosive packages and the initiation system, which will enable it to manufacture the ordnance for the utility industry.

Another key step in furthering the commercialization process was demonstrating the kinetic bonding on a prototype tube bundle with a reasonably large number of tubes. The recently completed demonstration involved making over 400 tube-to-tubesheet joints at one time. The tube bundle was composed of type-304 stainless steel tubesheets with titanium tubes. Because approximately 400 tubes can be installed in a condenser during one shift, this was a realistic number for demonstrating commercial viability. To show further that the process is ready for field use, Foster Wheeler personnel installed all the explosive packages and initiation rails. The simplicity of the installation procedure enabled the personnel to complete this step rapidly and easily after only brief training. Figures 1 and 2 are photographs of the prototype tube bundle with the explosive packages and initiation system during and after installation.

The kinetic bonding of condenser tube-to-tubesheet joints is now ready for use by utility members, either for shop or for field tubing and retubing. EPRI and Foster Wheeler are now making joint presentations of the process details to utility members who are planning condenser retubing. Interested utilities can easily arrange for such presentations.

Improved reactor water chemistry can lead to substantial savings by minimizing corrosion damage. Portland (Oregon) General

Figure 1 Foster Wheeler personnel installing explosive packages in a prototype tube bundle to demonstrate the simplicity of the procedure and its readiness for field applications.

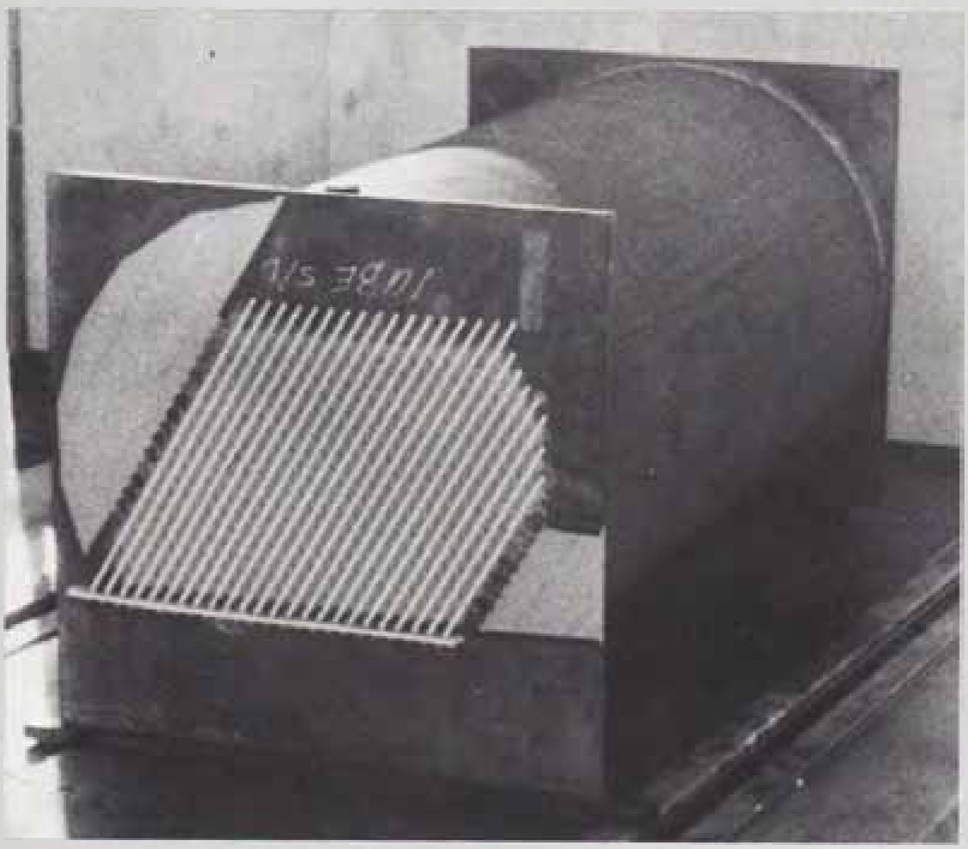


Figure 2 The prototype tube bundle with the explosive packages and initiation system in place, prior to firing the 420-tube shot that will help demonstrate the commercial viability of the process.

Electric Co. has calculated that improved water chemistry will save $200 million over the next 10 years at its Trojan nuclear station, and Public Service Electric and Gas Co. expects a $400 million savings at Salem Units 1 and 2.

Because leaking condensers are a prime source of reactor water impurities, improvements in condenser materials and joining procedures offer the potential for major cost savings and increased plant availability. The kinetic bonding process will be a key factor in greatly improving water chemistry by making leak-free condensers. *Project Manager: Wylie J. Childs*

ADVANCES IN REACTOR PRESSURE VESSEL INSPECTION

The reactor pressure vessel is the largest component in the pressure boundary of a pressurized water reactor (PWR) system. To ensure that these vessels meet the requisite high standards in construction and service, the American Society of Mechanical Engineers published the Boiler and Pressure Vessel Code. This code specifies conservative design standards and minimum inspection procedures for pressure vessels. NRC requires that utilities observe this code and various Regulatory Guides when carrying out vessel inspections.

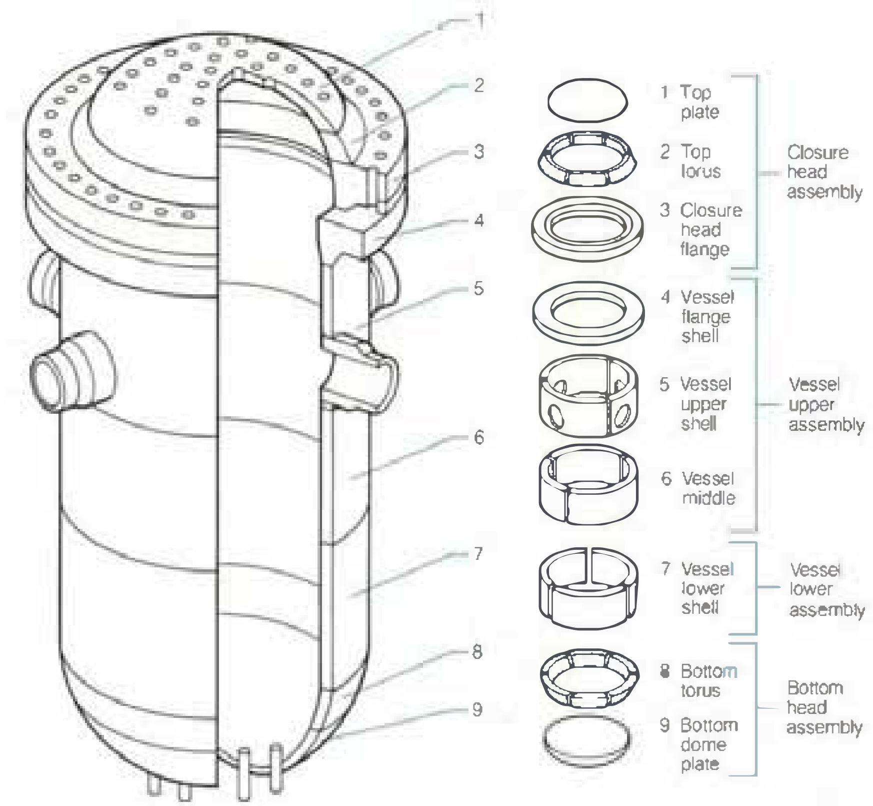
Reactor vessels are complex welded structures. The reactor consists of three rings, the so-called shell courses, a bottom torus, a bottom dome, a head flange, several nozzles, and the closure head assembly (Figure 3). Those components made from rolled plate have a number of longitudinal weld seams, all of which must be inspected during preservice and at 10-year (maximum) service intervals.

To protect the ferritic steel vessel from the corrosive coolant, a layer of stainless steel cladding is welded onto the inner surface. Machine-laid multiwire cladding or strip cladding is used over most of the surface. The circumferential seams, however, require hand-laid metal arc cladding because no cladding machine can handle the massive structures that are the result of joining two vessel rings together. These welds must also be inspected.

During fabrication, shop personnel use a combination of ultrasonic testing (UT) and X-ray inspection techniques. They make every effort to discover and remove all fabrication flaws before the vessel leaves the shop; this reduces the probability of finding a flaw during preservice, when repair is more difficult.

The preservice inspection includes a UT

Figure 3 PWR pressure vessel assembly. Rolled plates are welded in rings or shell courses and individually machine-clad. Circumferential welds joining a two-ring stack are clad by manual metal arc techniques.



examination to establish a baseline for comparison with periodic in-service inspections (ISIs), which are done ultrasonically. Because code sections governing shop, preservice, and in-service inspections specify somewhat different procedures, this baseline helps resolve some of the confusion that might arise over changes observed during later inspections.

To check for service-induced flaws an ISI normally involves inspecting the inner surface through the cladding because the outer surface is generally inaccessible. The ISI, which requires the unloading of all fuel and internal structures, usually is on the critical path of the outage. The method is to probe the metal volume with UT transducers at five code-required angles. Because the vessel is flooded and radioactive, the inspector uses a remote manipulator to move the transducers over the weld surface in axial and azimuthal directions.

Two factors have shifted the inspection emphasis from deep flaws to the near-surface region. First, in 1981 the NRC added Regulatory Guide 1.150, which emphasizes the need to inspect the region just below the inner surface. Inspection of this region is more difficult because of the strong reflections from the inner cladding surface and the large, irregular metal grain structure of the cladding. Second, growing concerns about pressurized thermal shock (PTS) highlighted the need to inspect the near-surface region of the vessel wall. In theory a PTS event could cause a small under-clad crack of 6 mm (0.24 in) to grow to an unacceptable size in a highly embrittled vessel wall.

If ISI is to take into account the PTS issue and its effect on determining future vessel operating suitability, only an inspection technique of excellent reliability is acceptable. Accordingly, the vessel inspection technology development effort at EPRI has shifted from concentration on deep flaws to an emphasis on the near-surface region.

Deep flaws

Prior to RG 1.150 and the PTS issue, the research emphasis was on the characterization of deep flaws in heavy section walls. The result was a series of laboratory feasibility studies, which led to the design and fabrication of an acoustic holography device for use on PWR vessels: the pressure vessel imaging system, or PVIS.

PVIS is designed to work underwater on the end of a conventional manipulator arm inside the vessel. The system produces images of deep flaws and displays them on a computer-driven CRT screen. PVIS can obtain images from any angle of inclined view and from any perspective (above, below, right, and left). The system can also superimpose images from different perspectives or inclinations.

The PVIS equipment was integrated with the manipulator and conventional ultrasonic inspection system owned by a commercial vendor of ISI services. A week-long, full-up test of the package, performed in an uncontaminated pool normally used for training, encountered only minor equipment problems. PVIS succeeded in imaging a number of flaws through typical cladding surfaces.

PVIS is currently at EPRI's Nondestructive Evaluation Center awaiting an appraisal of its capabilities and a correlation of its holographic images with more conventional UT data.

Near-surface flaws

In 1981 Electricité de France, motivated by the discovery of under-clad cracks in the nozzles of a number of vessels, worked out a successful solution to the problem of near-surface detection in clad structures (EPRI NP-2841). Although the French solution demonstrated very high detection reliability on flaws of ≥3 mm (≥0.12 in) in depth, the cladding in these nozzles was mainly smooth strip and well-ground manual, much more readily inspectable than the cladding in the beltline region of most U.S. vessels.

The French experience was encouraging but not conclusive. Strip cladding is relatively smooth, both on the surface and at the interface with the base metal, compared with other types of cladding. In addition, the degree of surface preparation is not well established for many U.S. vessels. Although the general practice is to hand-grind the cladding over the weld seams to aid inspection, few utilities can document surface finish or demonstrate consistent enforcement of quality control in grinding operations to the level of detail needed to ensure the applicability of the French data to a particular U.S. vessel.

In 1981 an experimental project was initiated to establish an under-clad crack detection capability for typical U.S. cladding. A number of test blocks were fabricated that contained a variety of cracks beneath all types of cladding. Three ISI vendors then tested their existing equipment for under-clad crack detection on these blocks. All tests were totally blind: participants had no prior information on the block contents.

The positive results were that the vendors could reliably inspect unground strip and three-wire cladding. The negative results were that manual cladding could be, but was not necessarily, inspectable; single-layer, partially ground manual cladding was clearly inspectable, but three-layer unground cladding was not. Further, three-layer, shop-smooth material could be inspected reliably only for cracks almost perpendicular to the cladding direction; all other crack orientations were problematic with existing tools.

To accommodate the PTS issue, detection reliability of very high levels is mandatory, and cracks at an arbitrary orientation cannot be ruled out. Therefore, the then-existing state of the art was clearly insufficient, and the demonstration of a more reliable method was necessary.

UDRPS

The ultrasonic data recording and processing system (UDRPS), used in conjunction with commercially available, surface-riding transducers, has demonstrated the necessary reliability. This combination of equipment repeated the blind tests on the same blocks, acquiring all data in an automatic mode. Detection reliability on all blocks, except the unground three-layer manual cladding, was 100% of all possible cracks. Sizing accuracy was also very good.

Pacific Gas and Electric Co. originally funded the UDRPS development, contracting it to Dynacon Systems, Inc. When PG&E was unable to continue the UDRPS effort, EPRI assumed support of further development and evaluation.

UDRPS is a high-speed, general-purpose signal processing device. Its major components consist of a large minicomputer, a high-speed data channel processor, a color video display, and disk/tape data storage devices. The high-speed data channel processor includes both a commercial array processor and a contractor-designed ultra-high-speed processor. The latter is necessary because the data processing rates needed to perform inspections within present outage schedules exceed the capabilities of commercial equipment.

UDRPS serves a number of valuable functions. First, it provides archival storage and rapid recall of all UT data: users can compare the results of the present inspection directly with the results of the previous one. Thus, for the first time UT inspection has a hard data backup reference analogous to a radiograph.

Second, the UDRPS computer code determines the presence of an "indication" by a complicated set of criteria, none of which is directly dependent on echo signal amplitude. These criteria include whether the signal-to-local-noise ratio threshold and the apparent motion of the target within the field of view of the moving transducer fall within prescribed limits. UDRPS applies these criteria to densely sampled data derived from raw data that have been averaged in space and time to ensure low noise. Then an analyst views the resultant patterns of indications on a display, color coded for signal-to-noise ratio, to determine whether the indications group in formations suggestive of cracks (e.g., length and depth, but no width). Only after the indication passes all these criteria does the analyst call a flaw detection. These calls have been highly repeatable, reproducible, and reliable.

Third, UDRPS enforces a uniform quality of inspection. Because UDRPS acquires all data under computer control, select important functional parameters (such as sampling pattern and density, calibration runs, gain settings, and so on) are controlled by the preset qualification test specifications written into the computer code, rather than by the operator. This allows the user to establish that field data are of the same quality as laboratory qualification data.

Specific results obtained by UDRPS in the blind test evaluations were based on the detection of 44 flaws (50% in each size class). These results are important to operators of reactor vessels. The probabilistic risk assessment of potential PTS events is proportional to the probability of an under-clad crack of 3–6 mm (0.12–0.24 in) occurring in the vessel wall; the most likely measure of the probability of detection was 95.8% (22 successes in 22 tries). The most likely measure of the probability of detection of a 3–12-mm (0.12–0.48-in) crack depth was 97.8% (44 successes in 44 tries). Sizing accuracy was ±1.3 mm (±0.05 in). Because very little current data exist on these probabilities, risk analyses have conservatively assumed that such cracks are present. Should tests demonstrate that UDRPS performs with equal success under representative field conditions, such inspection would reduce the risk from PTS.

Further work indicates that UDRPS can detect in-clad cracks, as well as tilted and skewed cracks. These latter detection capabilities will help to determine field procedures and system design.

Researchers have also applied the UDRPS device to deep flaws, demonstrating reliable detection on all of the eight flaws available and obtaining a sizing accuracy of ± 1.3 mm (± 0.05 in) by using a commercial 45° 2.25-MHz dual-element transducer. These results are encouraging although inconclusive for heavy section ISI.

The current project objectives are to design, fabricate, and qualify a field-usable UDRPS. This system will be designed to detect all under-clad cracks, regardless of orientation, at inspection times commensurate with current practice. The system will simultaneously obtain four independent measures of crack depth from the detection data; this will ensure accurate, reliable sizing. First field application is planned for 1986.

Further development of technology to detect in-depth flaws, possibly combining UDRPS and PVIS into one system, will follow. UDRPS has also been applied to BWR pipe inspection at two operating plants. *Project Manager: James Quinn*

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