Search for Plant Longevity

ELECTRIC POWER RESEARCH INSTITUTE

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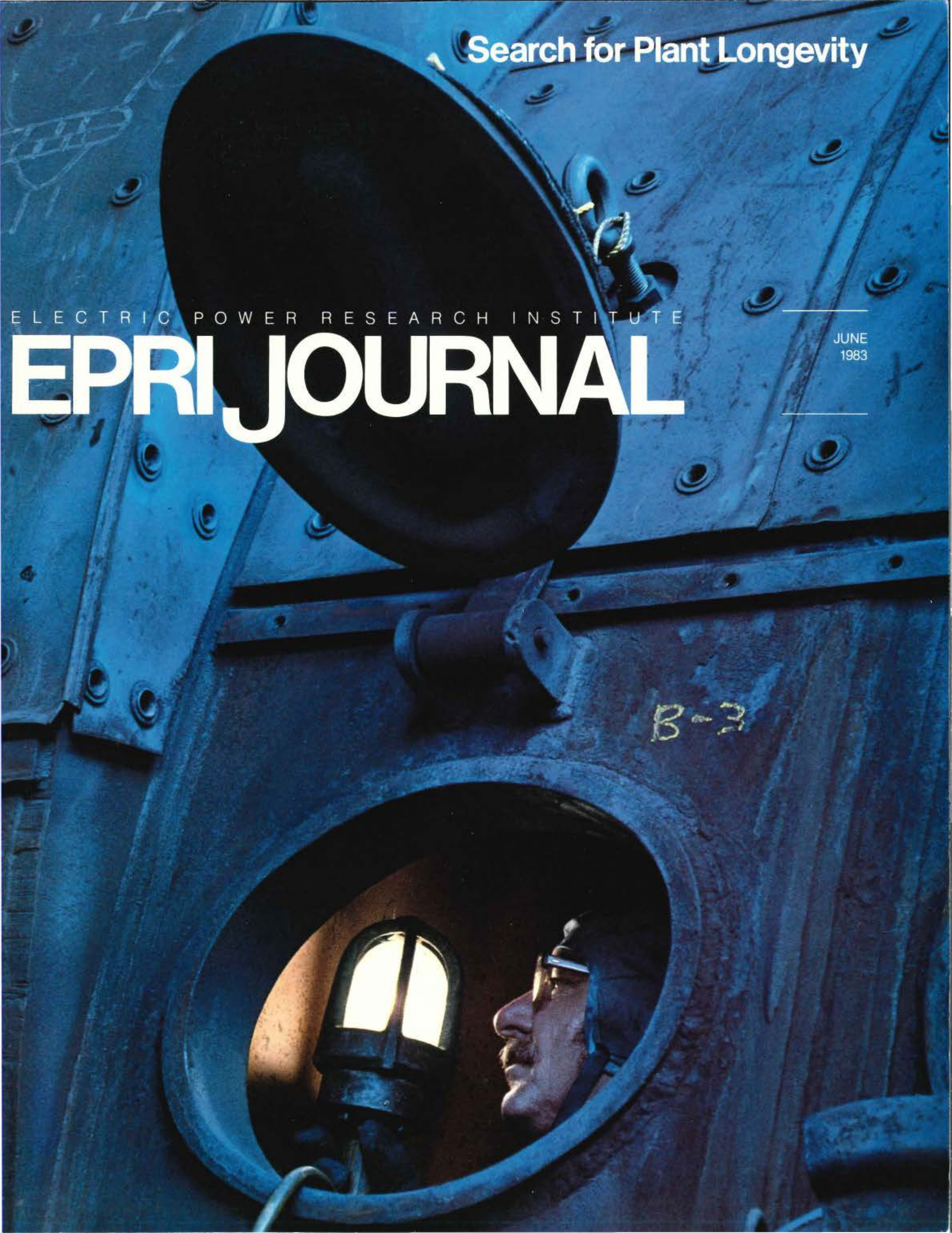

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Cover: Inspection and maintenance of major components are at the heart of attempts to extend plant life. Here a worker examines the structural integrity of the turbine assembly.

EPRI JOURNAL

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Longer Life for Older Plants

Extending the life of older fossil fuel power plants is a new option being pursued by the utility industry in response to a number of changing conditions: the high cost of money, high capital equipment costs, reduced and uncertain load demand, fuel price uncertainty, facility siting requirements, and environmental regulations. As a result, the only option for many utilities is to defer new construction for as long as possible. This trend will cause the average age of fossil fuel plants to increase by five years in the next decade, and the situation is likely to continue for the foreseeable future, possibly through the rest of this century.

Such a development will, of course, change the way the industry operates its plants. A typical plant life cycle includes many years as a baseload plant, followed by a change of use to cycling duty, a decreasing position on the dispatch curve, and, finally, placement in standby status. The forced-outage rate increases rapidly and plant operating costs go up substantially as the plant nears the end of its design life. To slow this trend and ensure economic and reliable service, new methods and practices will be required. Equipment upgrading, improved operating and maintenance procedures, methodologies for determining remaining component life, and diagnostic monitoring constitute the major industry needs.

A combined effort by the utility industry, equipment manufacturers, architect-engineers, and EPRI will be required to fill these needs. This month's lead article describes two basic efforts that are developing within the industry and EPRI for extending plant life: modification of existing technology for application to life extension and development of a confident approach to life extension decisions.

Fortunately for the first objective, existing technology offers many tools for implementing successful utility life extension programs. Life extension essentially translates into economical maintenance of availability and efficiency over an extended plant lifetime. Technology in use and under development for reliability, availability, and efficiency improvement, therefore, can be applied to life extension programs and provides a substantial base from which to work. Manufacturers and architect-engineers are now developing upgrading and uprating alternatives, and utilities are already initiating life extension programs.

The second objective, developing a decision approach to life extension, is more problematic. Because life extension as a generation expansion strategy is relatively new, the technology base required is not complete and support services are not in place. Decision-supporting tools need to be developed; for example, determination of whether life extension is the right strategy to meet the generation needs of a particular utility system requires a complex economic analysis of that complete system, with simultaneous consideration of many issues. Methods to confidently perform such an analysis are not yet available. Developing a methodology that integrates the necessary considerations will be the focus of EPRI efforts with utilities, architect-engineers, and equipment suppliers.

The work, which will require close coordination of all participants, will focus on upgrading methods for major plant components, derating approaches, maintenance practices, monitoring techniques, and economics. The goal is to provide the utility industry with the tools to extend veteran plant life at minimum life-cycle cost to stockholders and consumers.

Kurt E Yeager

Kurt E. Yeager, Director
Coal Combustion Systems Division

Authors and Articles

Which costs more, electricity from a brand-new power plant or electricity from a 45-year-old plant that is fully paid for but needs special care because of its age? **Extending the Lifespan of Fossil Plants** (page 6) reviews several R&D efforts by which EPRI is equipping utilities to make the right choice.

Author Nadine Lihach, the *Journal's* senior feature writer, drew major technical contributions from John Parkes and four of his colleagues in the Availability and Performance Program of the Coal Combustion Systems Division. Parkes has specialized in steam turbine reliability since he joined EPRI in April 1977, and he was named program manager in 1982. His major earlier experience was with General Electric Co. in steam turbine development. Parkes has BS and MS degrees in mechanical engineering from Queens University (Northern Ireland) and Union College (New York), respectively, and an MBA from the University of Santa Clara.

Anthony Armor manages projects in fossil fuel plant systems and performance, including diagnostic monitoring, especially the measurements that predict maintenance intervals and repair needs. At EPRI since September 1979, Armor was formerly with General Electric Co. He holds BS and MS degrees in mathematics and mining engineering, respectively, from the University of Nottingham (England).

Isidro Diaz-Tous, an EPRI project manager since 1978, guides research in the performance and reliability of steam turbines and their auxiliaries. He formerly was with Pacific Gas and Electric Co. Diaz-Tous graduated in mechanical engineering from Northrop Institute of Technology, and he earned an MBA at Golden Gate University.

John Dimmer, responsible for research in fossil fuel boilers and auxiliaries, came to EPRI in June 1977 after 15 years with The Detroit Edison Co. Dimmer has a BS degree in mechanical engineering from the University of Detroit.

Thomas McCloskey joined EPRI in 1980 to manage research projects for improved turbine reliability. He was formerly with Westinghouse Electric Corp. and holds a BS degree in mechanical engineering from Drexel University.

Three other staff members provided article background. Richard Duncan, of the Advanced Power Systems Division, manages research in combustion turbine technology. With EPRI since 1975, he formerly was with United Technologies Corp. Dominic Geraghty came to EPRI's Energy Analysis and Environment Division in 1973; he manages research in utility planning methods. Geraghty previously was an energy analyst and engineer with Irish government agencies. Ramaswamy Viswanathan is manager of mechanical metallurgy in Materials Support. He was with the Westinghouse Electric Corp. R&D Center for 14 years before coming to EPRI in 1979.

▪

Selecting the most economical future generating units is a utility planning problem that screams for solution by a computer. **Generation Expansion: Streamlining the Analysis** (page 16) reviews that problem and describes the solution recently produced under EPRI auspices—"a program too large," according to science writer John Douglas, "to be used on the computers available to most utilities only five years ago."

Neal Balu and Robert Iveson are the men behind the R&D and the article. Balu, who manages the system planning subprogram, joined EPRI in 1979 after working for seven years in the system planning department of Southern Company Services, Inc. Earlier he was on the Indian Institute of Technology faculty, Bombay, for four years. He holds graduate degrees in electrical engineering from Louisiana State University and a PhD from the University of Alabama.

Iveson, who manages the Power System Planning and Operations Program, also came to EPRI in 1979. He had been with New York State Electric & Gas Corp. for 20 years, including 9 years as supervisor of transmission planning for the New York Power Pool. Iveson graduated from Rensselaer Polytechnic Institute in electrical engineering and earned an MS degree in the same field from Syracuse University.

▪

Gaseous and liquid utility fuels from coal have been administratively separate R&D avenues at EPRI since its beginning. But economic and process linkages are asserting themselves now. **Peak Load Fuel From a Baseload Plant** (page 21), by science writer John Douglas, tells of a promising way to synthesize methanol—a very clean burning liquid—

from the products of a coal gasifier now under construction for utility demonstration.

Howard Lebowitz guided Douglas in reviewing the process problems that developers still face. Lebowitz, who has been with EPRI's Clean Liquid and Solid Fuels Program since December 1975, became its manager in 1980. He formerly was with Conoco Coal Development Co. as a group leader in liquefaction R&D. Lebowitz is a chemical engineering graduate of Pennsylvania State University.

Bert Louks provided background material on methanol process and product costs. Louks is a project manager in the Engineering and Economic Evaluations Program of the Advanced Power Systems Division. He has been at EPRI since November 1977, engaged mostly in assessments of novel fuel processes and power cycles. Louks was formerly an engineer-economist for SRI International, and he earlier held R&D, planning, marketing, and venture analysis posts with oil and gas companies. He graduated in chemical engineering from the University of Missouri.

■

Having been in the nuclear energy business since it began, Alvin Weinberg is truly one of the grand old men of what continues to be a new science. But as a researcher himself and as an adviser to EPRI, he is always looking ahead. **Alvin Weinberg: Forty Years a Futurist** (page 26) is feature editor Ralph Whitaker's impression from an interview.

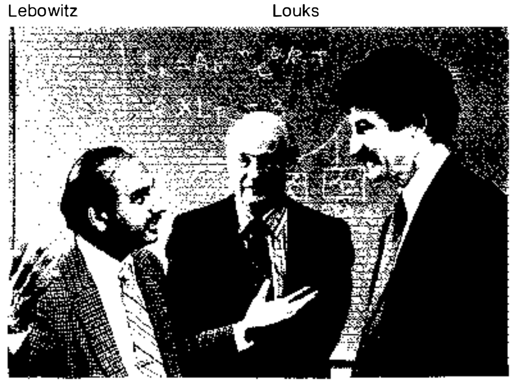
Diaz-Tous Dimmer McCloskey

Parkes

Armor

Lebowitz Louks

Iveson Balu



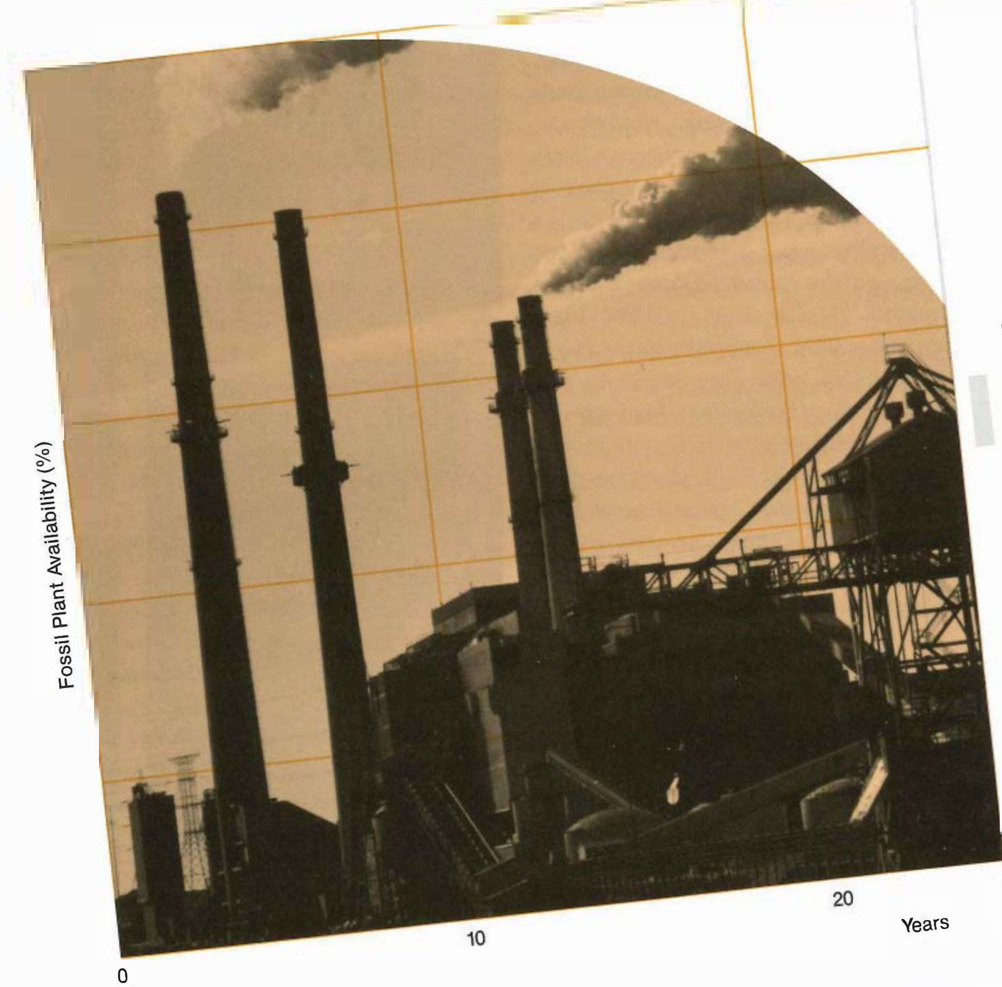
Viswanathan Duncan Geraghty

Forty years of age is usually retirement time for power plants. Boilers, turbines, generators, condensers, fans, and other components are nearing the end of their design lives, and efficiency, reliability, and availability are on a steady downward swing. As the plants become less and less economical, they are taken off-line, and newer units replace them.

Fewer new units

But electric utilities are not building many new units these days. Because of increasing capital costs and interest rates, new plants cost about $1200–$1500/kW to construct, compared with the modest $100–$200/kW price that utilities paid 20–30 years ago. With load growth almost at a standstill, revenues are down and few utilities can meet this asking price. Even utilities that can afford new plants are finding it harder to build them because environmental and land-use permits can take years to obtain. As new plants become less of an option, utilities are increasingly interested in keeping their old fossil plants around to meet electricity demand. These plants are already built, long since paid for, and require no new operating permits. They may no longer be in their prime, but utilities are nevertheless debating whether these veteran units should be retired or revitalized.

The central question is whether 40-year-old fossil fuel plants can be coaxed into generating power for an additional 10, 15, 20, or more years at a competitive cost. If money were no object, any plant could be patched up to run indefinitely, using as many replacement components and as much labor and downtime as required. But money is the object, and utilities coping with today's budgets have to carefully consider whether the cost of producing power from a plant over an extended life of perhaps 60 years



EXTENDING THE LIFESPAN OF FOSSIL PLANTS

The existing fleet of fossil fuel power plants is aging rapidly. As the cost of replacing retired plants becomes more prohibitive, utilities are seeking ways to operate existing plants well beyond their 40-year design lives. Comprehensive life extension programs are now being developed.

is less than the cost of producing power with a new plant. This requires objective assessment of older plants, including estimates of their future efficiency, availability, and reliability, the replacement parts they will require, the maintenance and operation techniques necessary to keep them running, and the outage time needed to accomplish necessary upkeep. In some cases, the bill could conceivably top the cost of constructing a new plant.

Because utilities have been considering life extension seriously for only the past few years, such assessments involve many worrisome uncertainties. The high cost of new plant construction and the arduous license and permit processes may discourage utilities from building new plants, but at least these are familiar uncertainties. Life extension, however, is unfamiliar. There are limited methods for evaluating the life of plant components, no infallible rules on maintenance techniques that will carry the plants through another decade or two, no black-or-white decisions on how aging plants should be operated, no cost-benefit analyses guaranteed to compare all the costs of new plant construction with the costs of old plant refurbishment. "We're groping," acknowledges one utility planner, and others in his position concede the same.

Unintimidated, many utilities are seriously considering life-extension programs for their aging plants, and several have initiated active programs in the last year or two. These utilities are working with in-house staff, equipment manufacturers, architect-engineers, and others to develop and carry out successful life-extension strategies. The utilities examine the plants in question, estimate how many good years they have left, and decide what has to be done to keep them running. If the payback looks encouraging, the utility can inaugurate a life-extension program that includes upgrading with new or improved equipment, rigorous maintenance and inspection, more judicious operation, or some combination of those three.

More utilities might consider life-extension programs if there were improved methodologies to assess the benefits of such programs, and better techniques, instruments, and plant components with which to implement them. Such refinements are now being developed by the utility industry, EPRI, equipment manufacturers, architect-engineers, and others.

Fortuitously, much ongoing industry research into improved plant reliability, availability, and efficiency is applicable to plant life extension as well. "Utilities have always sought to maintain maximum plant performance over the design life of the plant," explains John Parkes, manager of EPRI's Availability and Performance Program, Coal Combustion Systems Division, where many plant performance projects are grouped. "Now, because of economics, utilities want to maintain plant performance for 15 or 20 years beyond the original plant lifetime. Most of the projects that we've been working on for the past 6 years can help." To expand the existing research effort, EPRI recently began several new projects that address long-term life extension more specifically; other life-extension projects will be launched as additional utility needs are identified.

Life remaining

The first step toward extending the life of an older plant is to assess its present condition. To do this, a utility performs rigorous inspections, frequently calling in the original equipment manufacturers, architect-engineers, and consulting firms to help with the assessment. Utilities typically concentrate their efforts on the major plant components, such as boilers, turbines, generators, condensers, boiler feedwater pumps, and feedwater heaters. These systems cost the most in dollars and outage time if they fail, and they can make or break a life-extension plan. If several of these systems are debilitated, the utility may decide then and there to abandon life extension.

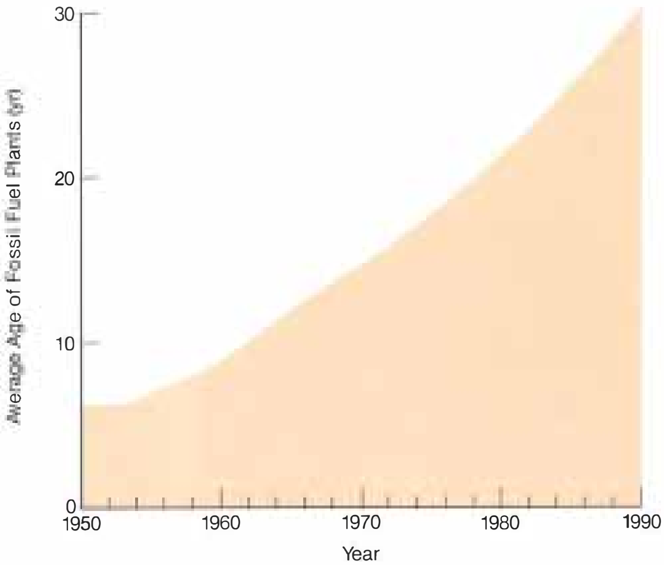
Much of the plant's present condition depends on how the plant was operated over its lifetime. Many large fossil fuel plants were originally designed as baseload units, intended to run steadily with as few starts, stops, and cyclings as possible. As these plants aged, and as newer, more efficient plants came online, the earlier baseload units were relegated to intermediate and cycling duty. These duty cycles, which require increased stops, starts, and load swings, were not what the plants had been designed for, so the thick metal parts of the plants experienced substantially increased thermal stresses. These stresses in turn affected the materials properties of the components and made them more susceptible to failure through fatigue, creep, and other conditions that significantly reduced the remaining life of critical plant components.

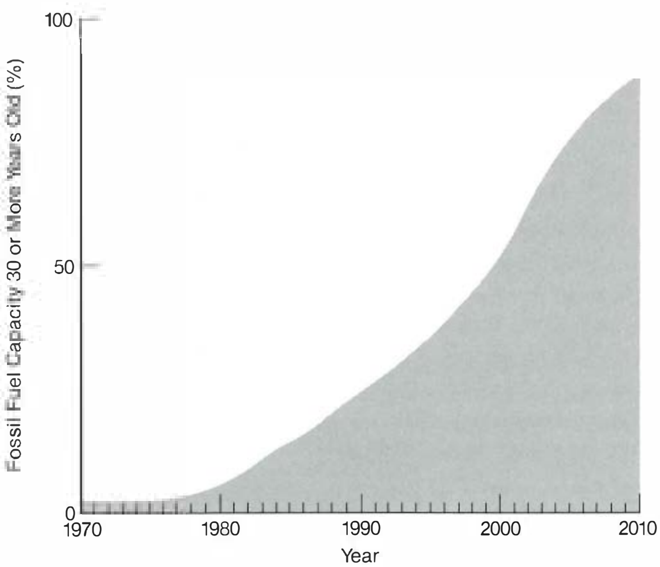
Utilities keep records on plant operating history, but direct examination of the plant's components is still the best way to determine remaining life. The trick lies in accurately assessing the record that these components hold. Utilities have been working on developing component examination techniques since the 1960s and 1970s, when new plants that were much larger and substantially different in design than their predecessors began to appear on utility systems. In some cases, the new designs caused plant performance to suffer, and utilities had to figure out ways to predict impending failures. With advance warning, utilities could schedule outages and stockpile spare parts. As a result of this ongoing research effort, today's utilities have techniques and tools at their disposal for determining the remaining life of plant components; yet these are not always as advanced as they need to be, and work to improve them continues.

A case in point is evaluation of thick-walled boiler pressure parts, such as drums, headers, and piping. Current techniques involving accelerated creep tests can provide reasonable estimates of remaining life, but they require large metal samples, which must be cut from operating components. John Dimmer,

Power Plant Demographics

After peaking in the early 1970s, fossil fuel power plant capacity additions have slowed considerably, a casualty of high interest and capital costs, reduced load demand, and increased siting and environmental regulation. In 1973, for example, some 23 GW were added to the industry's capacity; in 1982, only about 7 GW were added. As a direct result of this slowdown in plant construction, the average age of total fossil fuel capacity is increasing. By 1990, according to published statistics, approximately 25% of fossil fuel capacity will be 30 or more years old, and if present trends continue, that percentage will increase after 1990.





subprogram manager for boilers and related auxiliaries, explains that there are limitations on how many samples can be taken for these destructive tests and limitations on where they can be taken from. The techniques are also costly and time-consuming.

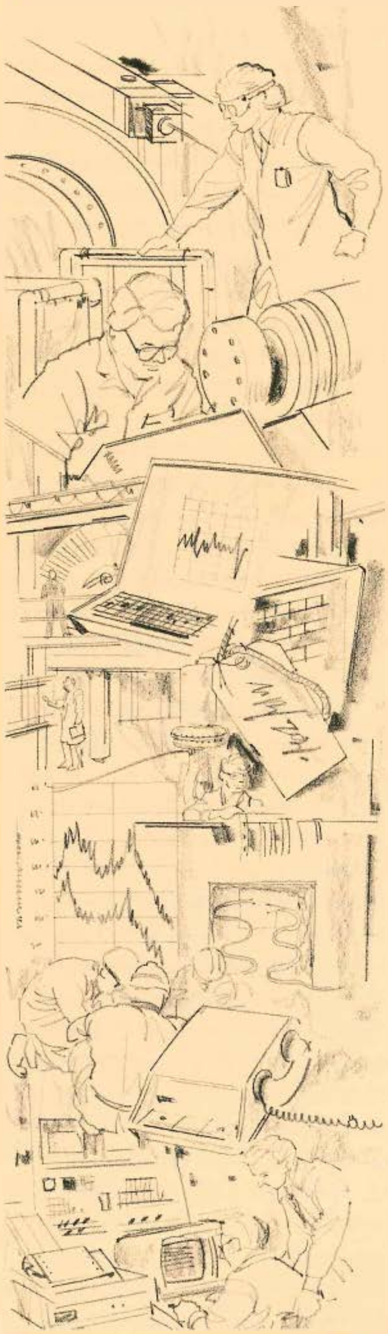
Two new techniques offer utilities a promising solution. The first, known as the metallographic technique, involves microscopic examination of very small samples—perhaps $\frac{1}{10}$ in—at high magnification. This technique may provide a direct and quantitative means of evaluating the extent of creep cavitation, cracking, microstructural changes, and other types of metallurgical damage that precede creep failure. The second technique, proposed by the Central Electricity Generating Board (CEGB; England), consists of standard creep testing, but of miniature specimens.

"Because both techniques require such small samples, they are essentially nondestructive, and the samples can be taken from anywhere in plant components," says Project Manager Ramaswamy Viswanathan of EPRI's Materials Support staff. "Periodic update assessments of remaining life should also be a relatively simple matter because there is no limit on the number of locations or type of locations that these minute samples can be taken from. The tests should also be faster and less expensive than today's techniques."

Encouraged by these two techniques, EPRI is working to develop and demonstrate a procedure that combines the two for an estimate of the remaining creep life of boiler pressure parts. Combustion Engineering, Inc. (C-E), and CEGB will perform the work, taking boiler header specimens from plants in the United States and Great Britain. The work should be completed and validated at utility sites by 1986. Although the present study addresses boiler pressure parts, the procedure is expected to be applicable to rotors, casings, and other high-temperature components.

After a utility has estimated how much

Steps to Life Extension



The first step toward power plant life extension is to assess the condition of the plant, particularly the remaining life of such critical components as boilers, turbines, and generators. Only through accurate assessments can a utility make sound decisions on whether to invest more money in an aging plant. The original equipment manufacturers, architect-engineers, and consulting firms are frequently called in to help with these assessments, which include component examination, diagnostic monitoring, and review of the plant's operating history.

Once a utility is equipped with information on the plant's condition, the second step toward life extension is a hard-nosed analysis that compares the cost of electricity produced by the life-extended plant with the economics of other options, such as a new power plant, load management or conservation programs, or power purchases. As many variables as possible must be considered, including the age of the utility's plants, the fuels used, current and projected reserve margins, general financial condition, opportunities to sell or purchase power, and environmental and regulatory conditions.

If life extension still looks like the best choice after economic analysis, the utility's third and final step is to develop a life extension strategy and implement it. The plan may include upgrading with new or improved equipment, diligent inspection and maintenance, and more careful operation. The strategies vary: a utility with 40% of its capacity idle may consider derating an older unit a good tactic to lengthen plant life; a utility that has a low reserve margin and is already obliged to buy much of its power from neighboring utilities may opt for upgrading to keep an older plant going.

life is left in critical plant components, it has to learn how quickly that life is being expended. This information is essential for life-extension assessments; it also serves as an important guide for setting operating specifications that will see the plant through the next 10 or 20 years of service. Although utilities collect this information in many ways, on-line diagnostic monitoring is becoming increasingly important for identifying plant stresses as they occur. By correlating such operating parameters as temperature, pressure, and operating mode with such variables as vibration levels and metal stresses, operators can get a better reading of how quickly the life of a component is being used up.

Diagnostic monitoring for all areas of the plant has advanced considerably in recent years. Diagnostic systems are available for boilers, turbines, generators, fans, pumps, heat exchangers, and other components. However, like inspections for remaining life, the degree of sophistication of these techniques is not all it could be. "Some monitoring techniques—vibration signature analysis, for example—are well developed and can be implemented in the near term for predictive maintenance procedures," comments Anthony Armor, subprogram manager for plant systems and performance. Vibration signature analysis has already been shown by CEGB to be capable of detecting large transverse cracks in turbine rotors during rundown, the phase when turbines are reducing speed. EPRI and General Electric Co. are now working on a project to see if vibration signature analysis can be used to detect smaller cracks during full-load, full-speed conditions.

"Other monitoring techniques, such as boiler stress and condition analyzers, require further development and field qualification before they can be generally applied to aging fossil fuel plants," says Armor. A boiler stress and condition analyzer that could pick up vital boiler information through thermocouples and relay it to a microprocessor would be particularly useful because the boiler is the number-one contributor to fossil fuel plant downtime. Although thermal stress analyzers are available for turbines, no system is commercially available to detect and collect information on the loss of life in boiler headers, tubes, drums, and other parts during either constant or cycling operation. EPRI and C–E are now developing a prototype system that can do just that, and demonstrations will begin this year at Consolidated Edison Co.'s Ravenswood station.

Improved analysis and evaluation techniques are also needed to diagnose and correct problems in critical plant components that are subject to failure from a variety of causes. Steam turbine blading is a good example. A turbine blade stress analysis computer program, under development by EPRI and Stress Technology, Inc., will provide an accurate method for predicting the fatigue life of steam turbine blades under actual operating conditions. Diverse stress-inducing factors, such as turbine speed, vibration, damping, and blade stiffness, will be fed into each fatigue analysis, together with material fatigue properties, according to Project Manager Thomas McCloskey. The computer program will provide information to utility engineers on the probable causes of blade problems and recommendations for both blade modifications and operating changes.

The tough decisions

Prepared with information on the aging plant's condition and future prospects, utilities now come to the really difficult decision—they have to determine if life extension is the right strategy for meeting their electricity generation needs, and if it is, how to implement it. Life extension's newness again puts utilities at a disadvantage. They are not yet fully familiar with determining the costs and benefits of keeping an old plant on-line for 20 more years, nor are they completely at ease with selecting life-extension strategies.

Utilities with ongoing life-extension programs have developed their own methods for cost-benefit analysis. However, most of these analyses focus on particular generating units rather than on the utility as a whole. To evaluate life-extension investments from a utility viewpoint, many additional variables must be taken into account: the age of all a utility's plants, the fuels used, current and projected reserve margins, the utility's general financial condition, opportunities to sell or purchase power, and environmental and regulatory conditions.

EPRI's Energy Analysis and Environment Division is now developing a general methodology that takes into account all the important variables for different utility situations. Working from an investment and risk analysis perspective, the methodology will compare new plant construction alternatives to plant upgrading alternatives (including life extension, as well as increased capacity, reliability, availability, and efficiency at existing plants).

"For example," explains Project Manager Dominic Geraghty, "a utility that is unwilling to commit to the large, long-term expenditure of a new plant might find life extension of an old but relatively efficient coal plant to be an acceptable investment of much lower risk. On the other hand, a utility with a high reserve margin, low load growth, and poor financial condition is unlikely to be interested in any capacity investment and may even consider retiring older, less-efficient plants."

The methodology is due to be completed by the fall of 1983 and will be published in workbook form. Varying levels of analytic sophistication will be offered, from a simple payback analysis to a comprehensive, computerized investment risk analysis. The simpler analyses can be used to screen several alternatives, while the more comprehensive analyses can be used as the utility gets more heavily involved in its assessments.

Life extension and new plant construction are, of course, not the only contenders for tomorrow's utility investments. They must compete for funding with other investment alternatives. Load management, which employs special rate structures and other incentives to achieve a more balanced use of existing plants, is one such option. Conservation programs and power purchases from other utilities are also possibilities.

Because many utilities have had to curtail their capital expenditures programs, it is important to choose options carefully. "Suppose you find out that life extension will save you $500/kW over new plant construction," says Geraghty. "You still might not want to spend your money on life extension. There may be lower capital requirements, a better return on investment, or lower risks associated with load management or conservation. The difficulty is in developing measures of equivalence with which to compare these very different alternatives." EPRI is developing methodologies that compare a utility's life-extension options with these other options.

How-to for utilities

Once a utility is convinced that life extension might be right for its situation, its next move is to develop a life-extension strategy. Here, again, guidance is required. There are many possible ways to extend plant life, and equally as many uncertainties. If a utility decides to install new or improved components to upgrade a plant, it has to calculate equipment costs, downtime, and ordering lead time. Some equipment can be changed out or repaired with relatively low cost, short downtime, and short ordering lead time; other equipment, particularly major components, entails high capital costs, extended outages, and long ordering lead times. Certain components may be obsolete or the original manufacturers may no longer be in business, and the utility may have to go to considerable expense and trouble to get replacements.

Perhaps the utility can minimize new equipment costs by instituting a vigilant inspection and maintenance program; but the utility has to tally up the cost of the additional manpower and inspection equipment. Perhaps operating the plant more gently, with slower startups and shutdowns and more-gradual cycling, might carry the plant through the years ahead; maybe the utility should simply derate the unit. Again, the utility has to debate whether it can afford the resulting reduced capacity. There are questions for every life-extension approach, and answers are needed before utilities can proceed confidently.

Some of the answers will come from a new EPRI project initiated this year. This project, a systematic study of how to extend fossil plant life by at least 50%, will develop generic guidelines for an entire plant and implement those procedures on several selected older plants. "A utility will be able to take the results, assess its particular situation, and decide if it should upgrade, derate, shut down, or maybe even mothball its plant for a time," says Armor, who is managing the project. "The strategy is unique for each utility."

For example, a utility with 40% of its capacity idle may consider derating an older unit to be a perfectly acceptable strategy. But a utility that has a low reserve margin and is already buying much of its power from other utilities may not be able to derate anything, even an older plant. To keep an older plant going at rated capacity with minimum outage time, this utility might opt to start an extensive diagnostics and maintenance program to ensure that any outages are anticipated and fully scheduled.

The new project will emphasize major plant components, such as turbines and boilers, and will study life expenditure of these components under such conditions as high pressure, high temperature, fatigue, and elevated rates of erosion and corrosion. Assorted plant operation scenarios will also be studied, including baseload, daily or weekly cycling, and periodic or continuous operation at loads above or below design levels. EPRI also plans to develop cost-benefit analyses that will consider component capital costs, plant downtime under different inspection and maintenance schedules, and operation decisions to increase life by lowering duty cycles.

Although major systems are the emphasis, auxiliary plant components will also get their share of attention. "From the front-end coal feeders, pulverizers, and conveyor belts to the back-end stacks, scrubbers, and electrostatic precipitators, everything has to be considered," asserts Armor. Boilers and steam turbines in tip-top condition can't run without carefully maintained auxiliary components.

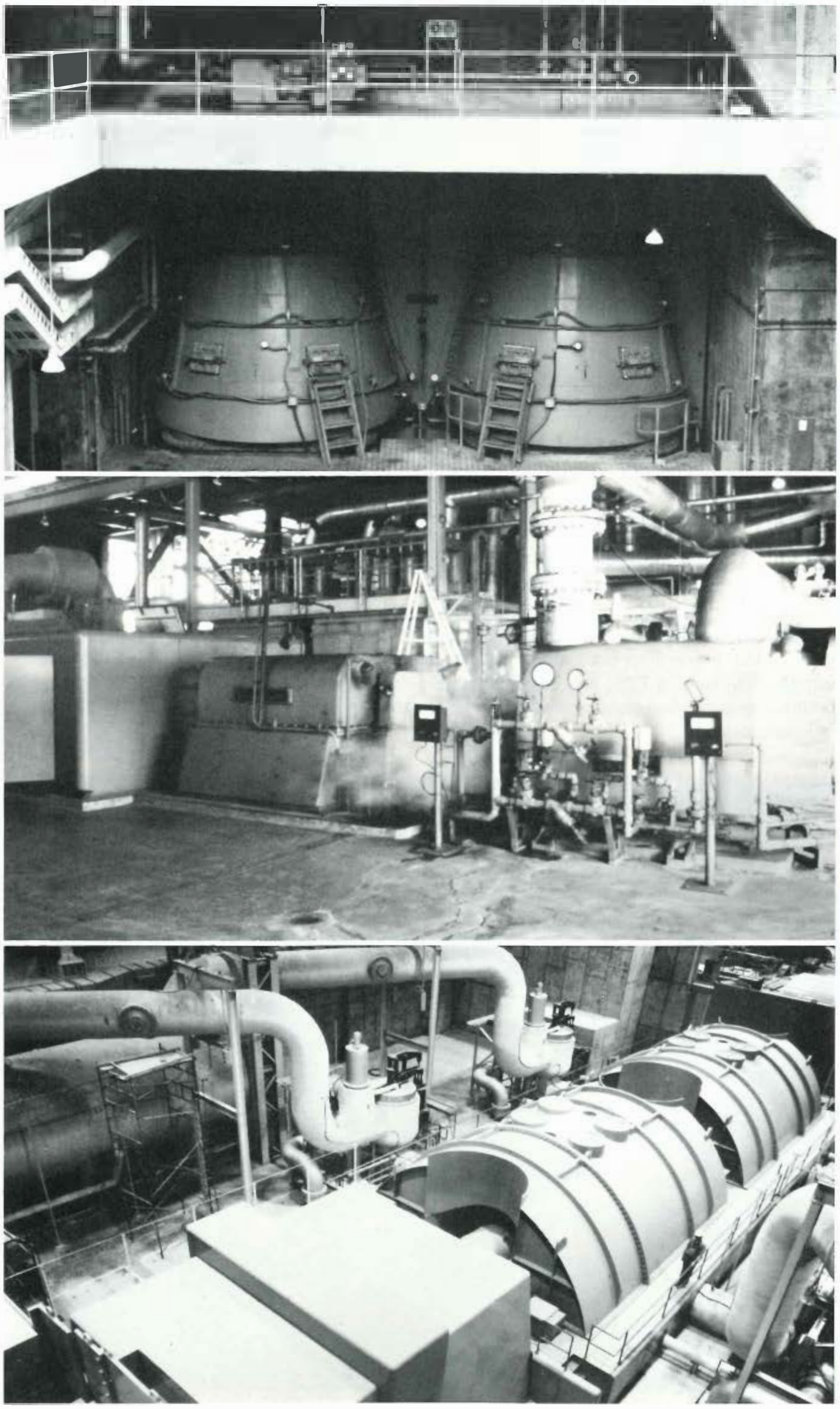
The four-year project has three phases: engineering studies, development of an implementation plan, and implementation. As currently planned, a team consisting of a turbine manufacturer, a boiler manufacturer, an architect-engineer, and several utilities will perform an in-depth investigation of each plant component from the perspective of life expectancy and refurbishment. Based on this engineering evaluation, an implementation plan will be assembled to apply the results to specific host utilities, covering representative unit sizes, ages, and operational modes. The cost of each upgrade will be identified and the overall cost per megawatt defined. Then the plan will be carried out at selected plants belonging to the host utilities. Throughout the project, additional R&D needs may be identified that the Availability and Performance Program will address as required.

Applicable projects

As noted, there are many other projects, both under way and completed, that can be applied in plant life-extension programs even though they were originally developed to improve the reliability, availability, and efficiency of existing fossil plants. These projects deal with a broad range of components, from major equipment to auxiliaries.

In the steam turbine area, for example,

Much of an aging plant's present condition depends on how it was operated over its lifetime. Many large fossil fuel plants were originally designed as baseload units, intended to run steadily with as few starts, stops, and cyclings as possible. Then, as these plants aged and as newer, more efficient plants came on line, the earlier baseload units were relegated to intermediate and cycling duty. Because the increased stops, starts, and load swings of these duty cycles were not what the plants had been designed for, the thick metal plant components experienced increased thermal stress, which in turn shortened their remaining life.



EPRI has evaluated several different coatings to help low-pressure turbine blades and disks resist corrosion. Testing of the turbine blade coatings (ion vapor–deposited aluminum, nickel cadmium electroplate, and fused Teflon powder) is continuing on turbine blades at Southern California Edison Co.'s Redondo Beach station. Steam turbine blades made of a titanium alloy that has superior corrosion fatigue resistance and good structural properties are also being evaluated as a replacement for conventional stainless steel blades. A row of titanium blades is due to be tested at a low-pressure turbine at Commonwealth Edison Co.'s Kincaid station.

Although most life-extension programs will involve large fossil plants with steam turbines, smaller plants with combustion turbines fired with oil and gas have also received life-extension consideration. EPRI's Advanced Power Systems Division cooperated with the Edison Electric Institute to issue guidelines on how to operate combustion turbines for a longer life. The secret, according to Project Manager Richard Duncan, is "mainly TLC—slower startups, slower shutdowns, and more-gradual loading." The division is also working on a thermal barrier coating for combustion turbine blades; this coating will permit turbine operation at higher temperatures or, in the case of aging plants, extended operation at standard temperatures. Advanced blade-cooling techniques will afford similar protection. This past year the APS division began a series of new projects aimed exclusively at life extension for existing combustion turbines.

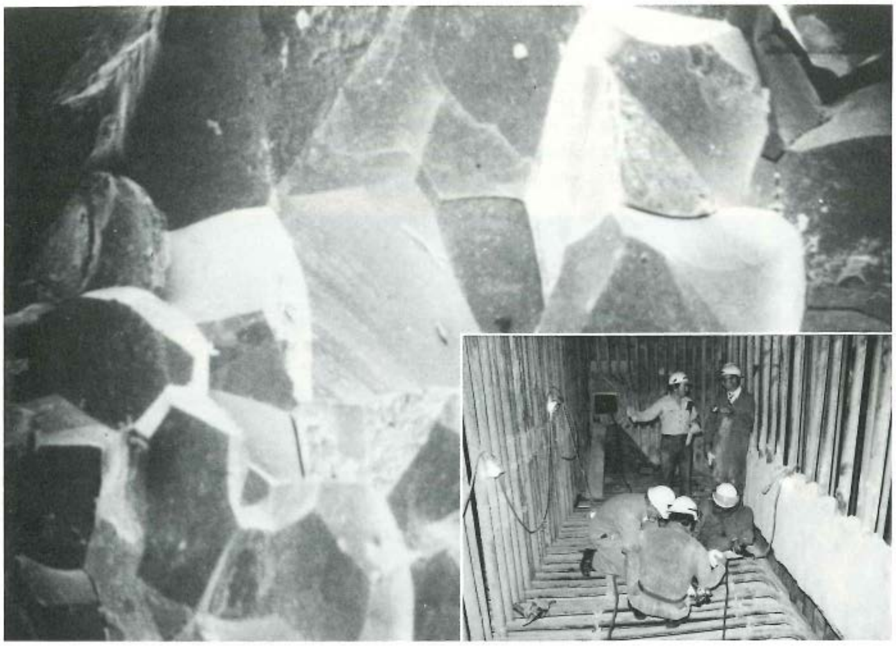
Major auxiliaries also have a considerable effect on plant life and are an integral part of any life-extension program. Condensers and boiler feedwater pumps are good examples. Condenser systems are the most significant source of corrodents in power plants; if leak-tight designs could be developed to minimize the entry of contaminants and air, utilities could save considerably on reduced corrosion in boiler and turbine systems.

UTILITIES COMPARE NOTES

Utilities may be old hands at keeping power plants humming for 35 or 40 years, but lasting 60 or so years is another story. Because plant life extension is such a new approach, it is helpful for utilities to get together to compare notes, swap experiences, and plot strategies. In Washington, D.C., this past March, a one-day meeting sponsored by Potomac Electric Power Co. (Pepco) attracted some 40 representatives from 15 utilities for that very purpose.

The meeting was reportedly the first time utilities have convened to discuss life extension. Attendees were primarily operation, maintenance, and engineering staff at supervisory levels, all anxious to know exactly how to keep units going past retirement. Presentations were made by utilities that have recently begun life-extension programs, including host Pepco, TVA, Pennsylvania Power & Light Co., Duke Power Co., and Baltimore Gas and Electric Co. EPRI was also on hand to discuss life-extension research.

After the utilities and EPRI explained their life-extension programs, attendees asked questions that ranged from how a utility can decide whether life extension is a good utility choice, to how the utility can actually carry it out. The consensus: "A lot of utilities are starting to move in the direction of life extension," says Anthony Armor, who represented EPRI at the meeting. "But they're still reaching for the methods to justify it and the tools to do it with." By the end of the meeting, the participants agreed to confer again. EPRI plans to hold a similar meeting in 1984 and will invite utilities, equipment manufacturers, architect-engineers, and others. □



Techniques for assessing a plant's condition are still short of perfect, but the industry is working on the problem. For example, to determine the remaining life of thick-walled boiler pressure parts, technicians now cut sizable samples from components for testing. Only so many samples from so many locations can be taken without jeopardizing the component. EPRI, Combustion Engineering, Inc., and England's Central Electricity Generating Board are now developing a new procedure that permits taking an appropriate number of samples from the desired locations; this essentially nondestructive technique requires minute samples, which are then subjected to microscopic examination and conventional creep tests.

Utilities also need improved techniques to determine how quickly plant component life is being used up, and on-line diagnostic monitoring systems are becoming increasingly available for that purpose. For example, EPRI and Combustion Engineering are now developing a boiler stress and condition analyzer that picks up vital boiler information through thermocouples and relays it to a microprocessor.

Minimization of condenser tube replacements would be another benefit. EPRI is now developing a highly reliable, corrosion-resistant condenser. Advanced operation and maintenance guidelines for condensers are also being developed and will be available by early 1984, according to Isidro Diaz-Tous, subprogram manager for steam turbines and related auxiliaries.

EPRI has also been working for many years to understand and resolve the rotor dynamics, cavitation, and hydraulic instability problems that plague boiler feed pumps. Interim design and procurement guidelines have been produced by EPRI and used by many utilities, and EPRI is now beginning a major project to design an improved boiler feed pump capable of highly reliable, long-lived cycling operation. Similar activities are being carried out for pulverizers, fans, feedwater heaters, and air preheater systems.

Even advanced pulverized-coal plant equipment has potential application as retrofit items to extend the life of older plants. One example is the spiral-tube boiler, widely adopted in Europe but used thus far in only one U.S. plant. This boiler's tubes spiral upward around all four boiler walls, unlike the tubes in conventional water-wall boilers, which travel vertically. Because the spiral tubes cross all four walls, the water in all tubes is heated to the same degree, resulting in reduced thermal stress of boiler parts and improved cycling capability. EPRI has plans to develop the technology for an advanced pulverized-coal plant over the next five or so years, and the project will evaluate the potential of the spiral-tube boiler.

This is only a small sampling of EPRI research into improved reliability, availability, and efficiency, yet it gives an idea of the many ways that this research can be applied to life-extension projects.

Down the road

Even if the economy picks up, the existing power plant population is going to be around for a long time to come. Plans for new plants slowed considerably after peaking in the early 1970s, and many of the plants that were planned were eventually delayed or canceled. As a result, the average age of fossil fuel plants is rising. By 1990, according to EPRI figures, about one-quarter of the fossil fuel plant capacity will be 30 or more years old. After 1990 that percentage could rise even higher. Because the future is always uncertain, it is possible that interest rates may be down, freeing more money for new plant construction. Yet new plants have long lead times, so even plants begun soon would not be completed for about 10 years. Consequently, utilities have to do something now to ensure that they will be generating electricity reliably in the future. Keeping veteran plants running may be the best way to do it. ■

Further reading

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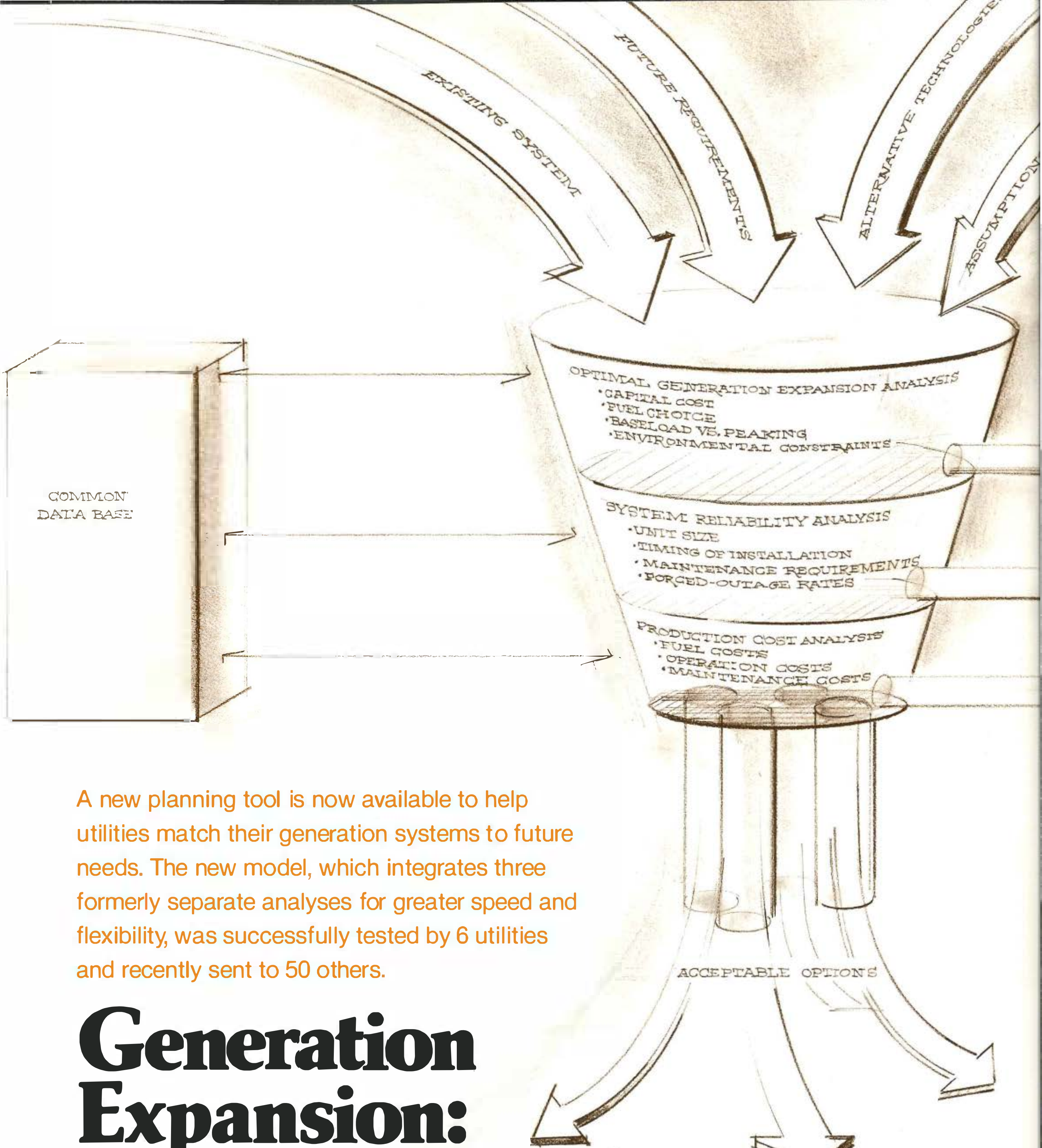
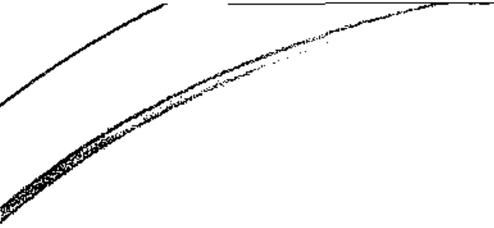
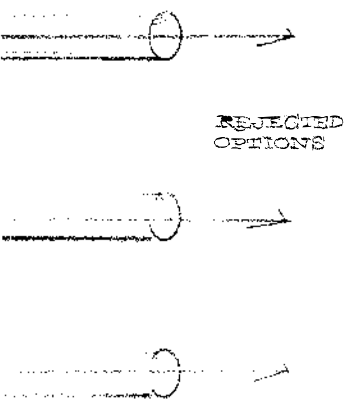
This article was written by Nadine Lihach. Technical background information was provided by Anthony Armor, Isidro Diaz-Tous, John Dimmer, Thomas McCloskey, and John Parkes, Coal Combustion Systems Division; Dominic Geraghty, Energy Analysis and Environment Division; Ramaswamy Viswanathan, Research and Development; and Richard Duncan, Advanced Power Systems Division.



A new planning tool is now available to help utilities match their generation systems to future needs. The new model, which integrates three formerly separate analyses for greater speed and flexibility, was successfully tested by 6 utilities and recently sent to 50 others.

Generation Expansion: Streamlining the Analysis





Very few decisions facing today's electric power utilities are as complex or important as those involving generation expansion. Choosing to build a new power plant can be a billion-dollar decision, which generally must be made at least a decade before the new facility actually goes on-line. To choose wisely, a planner not only must estimate future demand for electricity and the amount of generation that will be needed to supply it reliably but also must take into account growing financial and regulatory constraints.

Generation expansion analysis was once a fairly straightforward technical procedure. Those responsible could start with a load forecast in which they had some confidence, choose among a few well-established technologies to meet the new demand, then calculate how to minimize costs in a relatively stable business environment. Now, however, the problem has become far more difficult. Future growth is increasingly uncertain. Energy storage and alternative energy sources, like solar and wind power, must be considered as options. Environmental limitations must be taken into account. And choices need to be justified by an analysis that is detailed enough to satisfy public utility commissions.

As a result, utility planners today require computation tools that are both more complex and more flexible than those previously available. EPRI has responded to this need by developing a major new computer code, EGEAS (electric generation expansion analysis system). With it, planners will have the flexibility to choose among several different methods for optimizing expansion plans, using a unified data base and improved algorithms. The program is designed to help large utilities that are planning construction of new plants and smaller utilities negotiating future purchases of power.

"Generation expansion today has really become an art," says Neal Balu, project manager for EGEAS. "Utilities must be able to do their planning more intelligently, more carefully, and more scientifically, taking all factors—including uncertainty—into account. Previously, they had to work with computer programs that dealt only with parts of the problem. We're trying to give them a compatible whole. Both large and small utilities will be able to use EGEAS to reduce costs in planning for the future."

Under EPRI sponsorship, the mathematical foundation and models for EGEAS were developed by the Energy Laboratory of the Massachusetts Institute of Technology; Stone and Webster Engineering Corp. coded the actual computer program.

Why planning is so complex

The importance of generation expansion planning is that it can be used to reduce the two largest expenses of most utilities: the capital cost of building new power plants and the cost of fuel for running them. By delaying construction of a new generator for even one year, a utility can save millions of dollars in interest charges. Striking just the right balance among fuel options can also reduce overall operating costs by billions of dollars. But mistakes are equally costly—building too much generating capacity is wasteful, while building too little can threaten a system's reliability.

Calculating the detailed effects of such complex trade-offs has long been the task of a variety of computer codes related to generation expansion. Ever since computers became commercially available shortly after World War II, utilities have recognized the need for developing sophisticated analytic tools that could take advantage of this burgeoning technology. EGEAS represents the current state of the art; it is a program that would have been too large to be used on the computers available to most utilities only five years ago. In developing it, EPRI's aim was not only to provide planners with a more consolidated, efficient approach to tasks that were once handled separately but also to offer utilities more opportunity to participate in tailoring a code to fit their changing needs.

An information funnel

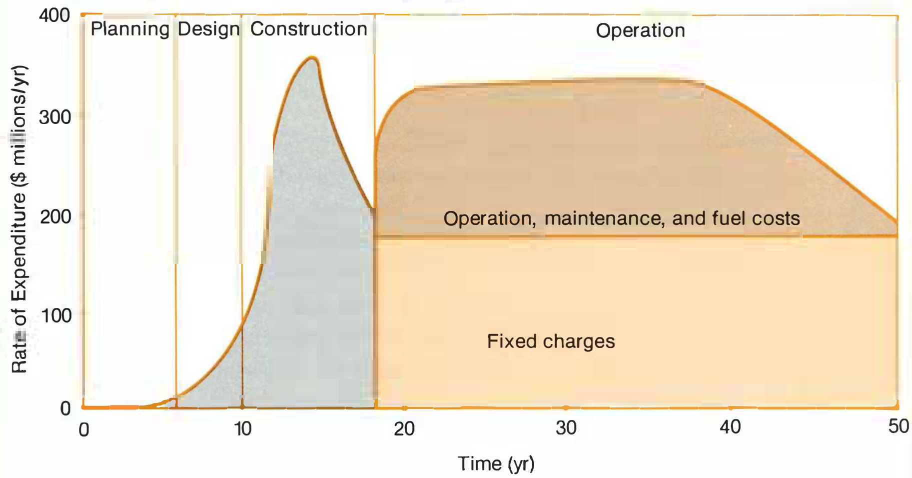
Conceptually, the steps involved in generation expansion planning can be pictured as a funnel of information, according to Robert Iveson, program manager of EPRI's Power System Planning and Operations Program. Into the top of the funnel go all the available data and forecasts about load growth (total kilowatthours of energy to be generated) and demand growth (kilowatts of generating capacity needed to meet peak demand). Out of the bottom eventually emerge a few scenarios showing what kinds of plants should be added to a system, when, and how their total cost (capital plus fuel) can be minimized.

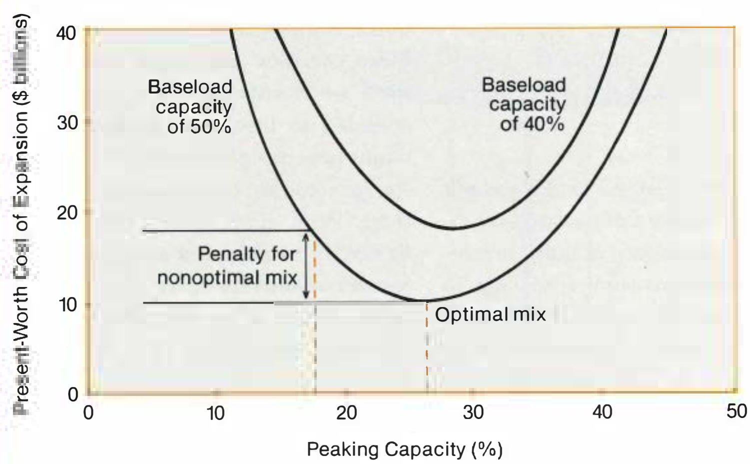
Along the way, three separate kinds of calculations take place. First, from information about future growth of load and demand, a broad outline of optimal generation expansion is calculated. This shows how many plants will be needed over a given period of time (usually 10 to 15 years into the future), what type they should be (baseload, intermediate, or peaking), and what fuels should be used. Several computer codes are now commercially available to handle these calculations by themselves.

Typically, the data emerging from optimal generation expansion programs would be further analyzed by hand before planners decided which parts of the information to pass on to the next step of computerized calculations. This massaging of the data—to use the common jargon—is sometimes painfully time-consuming, but until recently it was the only practical way to use human judgment and experience for paring away extraneous results. Neither the available computers nor the codes written for them were able to do the whole job efficiently.

Having once decided what kinds of new plants will be needed, the second step for planners is to perform calculations that determine a schedule for their introduction, including what size units will be selected and when these should be constructed. Generally, such decisions depend on the need to maintain system reliability, so a variety of computer codes are available to perform this step of analysis based on calculations of loss-of-load probability or other indexes of re-

Although expenditures during the planning phase of a typical large power plant (1000 MW) are relatively small, they carry tremendous leverage because they can significantly reduce expenditures during the operation phase. The task of generation expansion modeling is to optimize both fixed and variable costs that will continue for more than three decades of operation.





The EGEAS model allows the planner to determine the optimal percentages of base, intermediate, and peaking capacity. Missing the optimal mix by even a few percent can cost a utility billions of dollars. The cost of expansion is expressed in terms of the present worth of capital and operating costs over the next 20 years.

liability. A common figure of merit used in such programs is one-day-in-10-years reliability. In other words, the computer determines what schedule for adding new power plants will meet the given forecasts of demand growth while keeping the probability of system generation not equaling system load once in 10 years. (It should be emphasized that this number was chosen mainly to serve as a planner's benchmark, not as an actual criterion for system planning, design, or operation.)

The results of this second round of calculations consist of many possible schedules for introducing new plants. Some of these can be rejected out of hand by utility planners, based on the priorities of their own company. Traditionally, these extraneous results would again be culled by hand. The resultant set of acceptable alternatives would be passed on to a third computer program for a final series of calculations designed to select those with minimum cost.

Production costing

As one might expect, the fineness of detail that must be considered during the various stages of computation increases considerably as the bottom of the information funnel is approached. In particular, the cost of generating electricity ultimately depends on hour-to-hour decisions about which generators to use to meet the demand of the moment. Calculating and comparing production costs for a variety of generation schedules is thus potentially a tremendous task, even for a large computer.

The most accurate way to calculate annual production costs is to determine which generators are on-line for each of the 8760 hours in a year and to total their individual cost contributions. There are several commercially available computer programs that do just this, and their use will continue when an exact analysis of a given system is needed. However, for planning purposes this chronological approach can often be replaced by a more approximate one that is based on the relative probability that so many generators will need to be on-line at any one time. Although some probabilistic computer codes for calculating production costs have been commercially available, one of the specific breakthroughs achieved by EGEAS is to offer a computationally efficient method for making these approximate calculations.

From the production costing step emerge a few preferred scenarios for introducing new generation capacity to a utility system. This is the bottom of the information funnel, because each scenario not only contains enough capacity to fulfill anticipated growth in both load and demand but also adds new units in a way that maintains system reliability and does so at close to minimum cost.

Even under the best circumstances, threading one's way through the multiple steps of generation expansion analysis is a complex procedure. However, as now done, the task is made even more difficult by what Iveson calls the "constant finagling of data" between steps. "The aim of EGEAS," says Balu, "is to help solve this problem by reducing unnecessary manipulation of intermediate data, while consolidating and speeding up the individual calculations that make up generation expansion analysis."

Streamlining the analysis

Before attempting to develop a new computer code, the EPRI research team first interviewed utility planners and their supervisors across the country. The aim was to involve potential users in the design process right from the beginning. A team of industry advisers, representing various utilities, also became involved in the project, and EGEAS became a major topic of discussion at a series of workshops and industry committee meetings. Out of this utility needs assessment came a set of specific recommendations on how the computerized analysis could be streamlined and made more useful.

Topping the list were the need for a common data base to be used in each step of the analysis and the need to have multiple analysis options for tackling the expansion problem. Managing a common data base is a major programming challenge, one which also requires access to a large amount of computer memory. The benefits, however, are worth the effort. Rather than massaging the data by hand for each step of the analysis, a planner can now select the necessary information at any point from data already in the computer. Results of intermediate calculations are reported by EGEAS in such a way that critical human judgment can still be exercised, but without a lot of manual number shuffling.

A common data base also facilitates the use of several different analysis options that offer varying degrees of speed and accuracy. At one extreme is a screening curve option that yields a quick comparison of investment alternatives under steady-state conditions. It does not model the effects of changes in relative costs or take system reliability into account. A linear programming option shows how predetermined cost constraints will affect various generation alternatives over time, but cannot yield substantial information on unit sizes or reliability problems. Both of these options would normally be used to make preliminary studies of proposed generation alternatives to show which are promising enough to warrant more-detailed analysis.

A generalized Benders' analysis option represents a breakthrough accomplished in this project in optimization programming—a rapid but fairly accurate way to perform probabilistic production costing subject to a given reliability target. The method works by making successive approximations until the results fall within a specified range of accuracy. A unique capability of the generalized Benders' option is to estimate the marginal cost of reliability to a utility—that is, to tell how much it will cost to make a system "just that much more" reliable. What this EGEAS option cannot do in its present form is to model the transmission system interconnections or calculate costs by using subyearly periods.

The curse of dimensionality

The most detailed and sophisticated method of analysis in EGEAS is the dynamic programming option. It includes the probabilistic production costing capabilities of the Benders' method, but it is also suitable for modeling transmission interconnections and for making calculations over periods of time much shorter than a year. This capability is critical for making the most detailed analysis of costs, reliability, and maintenance scheduling. The problem is that the amount of computation required for dynamic programming increases exponentially with the number of alternative types of generating units to be considered.

This problem is called the curse of dimensionality and means that care must be taken to avoid using up inordinate amounts of computer time. To limit the number of alternatives requiring analysis, various limitations, called narrow tunnel constraints, can be imposed. These may be derived from previous analysis by using the generalized Benders' method. Thus the analytic optimization options of EGEAS not only are designed to be compatible but actually are complementary.

Other features

Included in these multiple analysis options are a variety of other features requested by utility planners. Because of the increasing importance of alternative energy sources, EGEAS includes provisions for modeling solar, wind, and other nondispatchable generation technologies. The problem with these, as the name implies, is that a utility cannot exercise full control over them. Solar energy is not available at night; wind power is fairly unpredictable; and industrial cogenerators supply power to the grid according to their own schedule. In addition, many load management techniques and customer conservation efforts have a similarly unpredictable effect on system generation requirements. Formulas for calculating the impact of nondispatchable sources on production cost and reliability have been developed for EGEAS.

A similar problem arises when one considers energy storage. Here the major constraint is not unpredictability but the inherent limits to the amount of energy available. This affects the loading order of units to a system, assuming that reliability is to remain constant. The impact of such limited energy sources on costs is calculated in EGEAS by considering how much conventional power generation is displaced.

Environmental considerations can be taken into account in a variety of ways. Actual limits on emissions can act as constraints both within a generation site (or surrounding area) and within a total system. Limits can include the total mass of sulfur or particulates emitted at a site, the amount of water consumed, the quantity of heat given off, and the total acreage of land to be used. A special data base is used to keep track of such basic site information as wind characteristics, ambient concentrations of various pollutants, and information on local water conditions. These data provide a link to other computer codes used by utilities to calculate the amount of abatement equipment that would be needed to make a given plant meet required standards.

At the request of utilities, several features have been added to EGEAS just to make it easier to use and modify. Most important, the code is modular—broken up into progressively smaller segments that culminate in hundreds of small routines. These routines generally contain fewer than 200 programming statements each, a critically important aid for debugging and modifying a large code that has more than 70,000 statements altogether. The code is also designed to be very flexible. A user may, for example, specify in advance the amount of interim results that will be reported.

Shakedown testing

EGEAS was designed as a production-grade computer code. This means it must meet specific standards for usability, documentation, and of course, reliability. To make sure EGEAS lived up to these standards, the code was sent out for shakedown testing by six utilities: Florida Power & Light Co., Public Service Co. of Indiana, Public Service Electric and Gas Co. (New Jersey), New York State Electric & Gas Corp., Southern Company Services, Inc., and the Tennessee Valley Authority. The experience gathered during these tests was then shared with representatives of other utilities at seminars held in Palo Alto, California, and Washington, D.C.

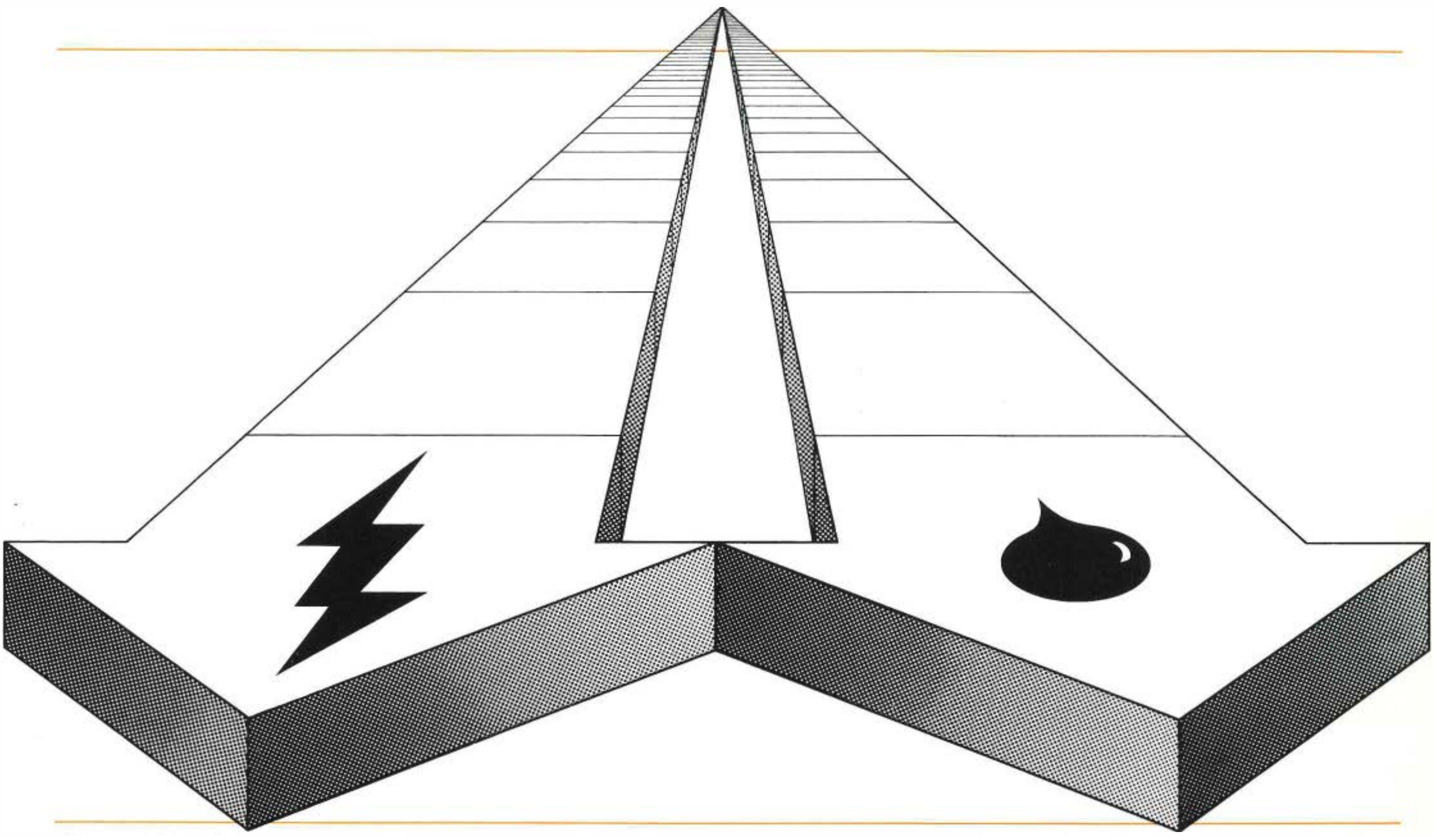
Most of the responses were quite favorable. As one utility representative involved in the testing put it, "The EGEAS program is a step ahead of other planning tools available today." Another reported that the time required for production costing calculations was less than half what was needed with the commercial program used previously. A third said that installation had been "fairly quick and smooth." A fourth said, "EGEAS program documentation is excellent. Its level of detail is greater than that typically provided for commercially available software." A few problems were also reported, mainly dealing with the way pumped-hydro storage is treated by the program. Work to correct these problems is now under way.

Even before testing had been completed and the program offered for general use in May 1983, word had apparently begun to spread. By late February, EPRI had already received requests for copies of the code from more than 50 utilities, 3 public utility commissions, and 4 agencies in foreign countries.

Balu wasn't surprised: "Utilities are caught in a vicious circle. Traditionally, they have tried to keep reserve margins between 25 and 30%, but now with constraints on both capital and fuel, some are down below 15%. And the harder they push their old units, the lower reliability gets. They need to be able to plan expansion with minimum cost for both capital and operations. We believe EGEAS will help them meet this need."

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

PEAK LOAD FUEL FROM A BASELOAD PLANT

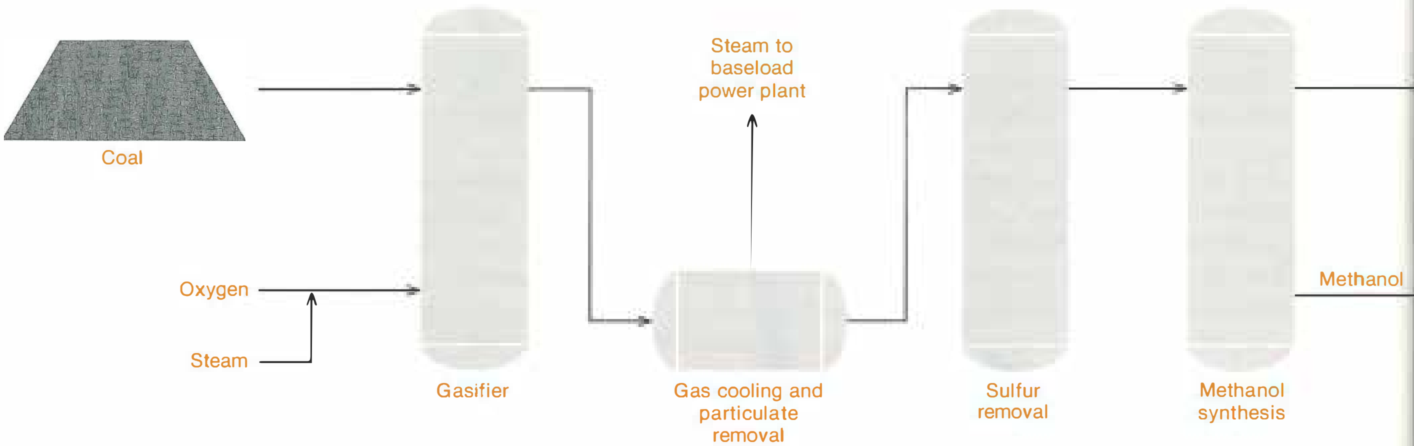


Coproduction of electricity and methanol appears to be a promising way to reap maximum benefit from an already attractive new technology: the coal gasification–combined-cycle power plant. A high-quality, easily stored liquid fuel, methanol could be used on- or off-site for peaking turbines, or even for fuel cells.

Except for its cost, methanol would be an almost ideal turbine fuel for generating electricity. It contains no sulfur or nitrogen compounds or ash that can cause air pollution. It burns at a relatively low temperature, which inhibits formation of nitrogen oxides, and it can be easily transported and stored. By coproducing methanol and electricity in a gasification–combined-cycle (GCC) power plant, this technically attractive liquid fuel may soon become economically competitive as well.

Concern over the security and cost of liquid fuels goes back to the 1973 OPEC oil embargo. Eventually, this concern led to the Fuel Use Act of 1978, which prohibited electric utilities from using oil or gas in new power plants, except for peaking. As a result, EPRI has been very active in seeking environ-

Methanol can be produced from coal in a once-through process that uses unconverted gas to generate electric power in an efficient combined-cycle plant. The methanol itself can be either used for on-site peaking generators or transported to areas that need a particularly clean-burning fuel.



mentally attractive alternative fuels that are available on a stable basis at reasonable cost.

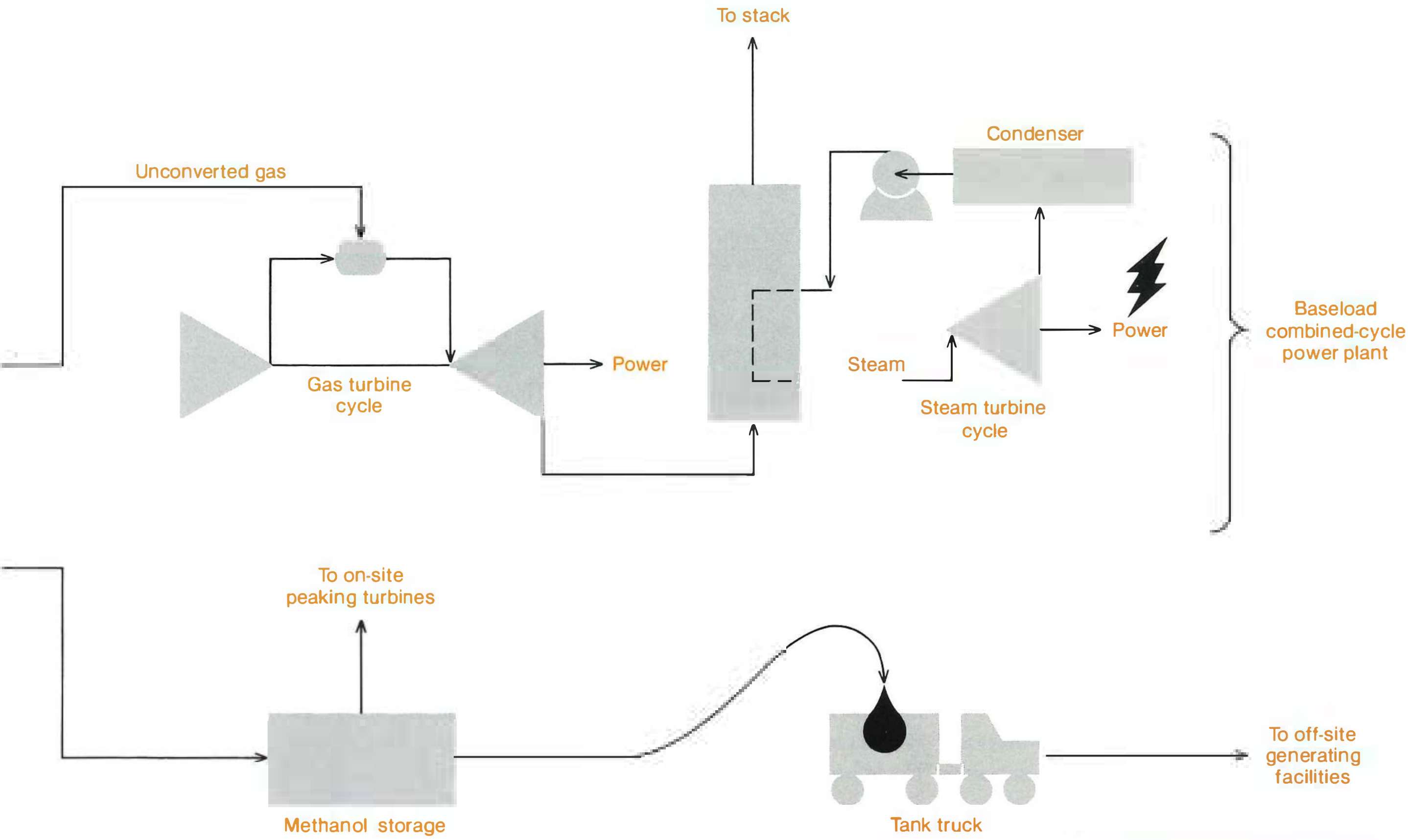
At today's prices, methanol (currently produced from natural gas) is not a serious contender. In terms of cost per million Btu, methanol purchased on the open market runs about $11.50, compared with around $7 for distillate fuel oil. Even if utilities, using current technology, made their own methanol from coal, the cost would be about $8 per million Btu. However, if a new process being developed with EPRI funding is successful, utilities may someday be able to make their own methanol for an estimated $5–$6 per million Btu, in terms of today's dollars.

Three options

To bring about such a desirable outcome, several technical hurdles must be surmounted, and some remaining economic uncertainties must be resolved. This will involve making critical choices among three alternative plant designs that could be adopted for making methanol from carbon monoxide and hydrogen produced by the coal gasifier in a GCC plant.

In all three types of plants, methanol is synthesized by combining hydrogen and carbon monoxide gases in the presence of a catalyst. However, conventional methanol synthesis requires more hydrogen than is called for by the basic reaction ($2H_2 + CO = CH_3OH$), and the advanced gasifiers in which EPRI is interested ordinarily produce the gases in nearly equal amounts, or perhaps slightly richer in CO.

The first type of plant uses an additional step in the process—a shift conversion—to obtain the proper reaction ratio and thus maximize methanol production. In this shift conversion, some of the carbon monoxide is reacted with steam in the presence of a catalyst to produce the desired ratio of hydrogen to carbon monoxide. Carbon dioxide is formed as a by-product of this shift reaction and must be removed from the shifted gas, along with any sulfur contaminants. A plant dedicated solely to producing methanol would employ the shift conversion step and would recycle



any unconverted gas back to the methanol reactor until it was all consumed.

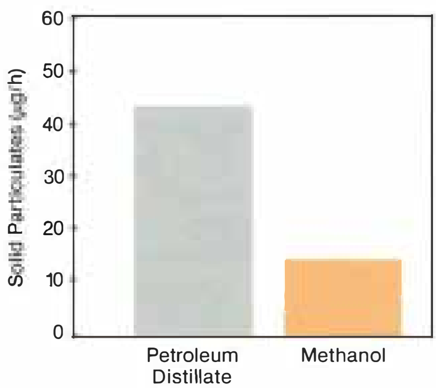
The second process, called the shifted once-through process, also uses the shift conversion but burns the unconverted gas remaining after methanol synthesis as a turbine fuel in a combined-cycle power plant rather than recycling it. Although the fraction of the gas converted to methanol is less than in the first process, a facility based on the shifted once-through method would cost less to build and would conserve energy. The unconverted gas would provide economical baseload power in the highly efficient combined-cycle plant, while the methanol could be used to replace expensive oil in peaking and intermediate-load generators. The major disadvantage of the process is that it still requires expensive shift conversion and carbon dioxide removal. This method of coproducing methanol and electricity can be performed with commercially available gasifiers and methanol reactors.

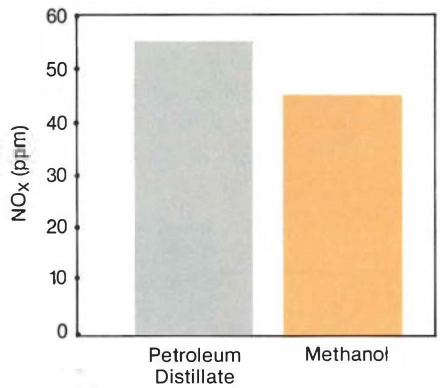
The third alternative, unshifted once-through synthesis, would eliminate both the recycle and the shift conversion–carbon dioxide removal. Elimination of these steps gives this option the greatest potential among the three alternatives for reducing capital cost and saving energy. Success of unshifted synthesis depends on the development of a process and a special catalyst that can produce methanol by using the roughly one-to-one ratio of hydrogen and carbon monoxide that emerges from fluidized-bed or entrained gasifiers. Because of its advantages, the unshifted once-through process is now the subject of considerable EPRI research, which is focusing on the remaining economic and technical questions.

Search for a catalyst

At the heart of the unshifted once-through system now under consideration is a methanol synthesis process originally developed by Chem Systems, Inc., with funding by EPRI and others. The challenge here is to mix and transport the reacting gases at the appropriate temperature while bringing them into contact with a catalyst. The Chem Systems pro-

The Air Products synthesis gas generating facility at La Porte, Texas, will be the host site for a 5-t/d pilot plant now being built to test Chem System's methanol synthesis process.





Methanol is a particularly clean-burning fuel. Tests comparing gas turbine emissions from methanol combustion with those from petroleum distillate fuel were conducted at Southern California Edison Co.'s Ellwood facility in Goleta, California. Methanol proved superior for particulate and NO_x emissions and produced no sulfur emissions.

cess accomplishes this by having the gases flow upward in a reactor together with an inert oil containing small pellets of catalyst. This three-phase fluidized bed—known as an ebullated reactor—not only provides an excellent mixing system for the catalyst but also simplifies removal of the heat given off during the reaction and allows for easy separation of the products. Methanol vapor is contained in the gas leaving the oil medium at the top of the reactor. It is then condensed to a liquid that is stored after unconverted gases are removed.

Technical feasibility of the Chem Systems reactor has been demonstrated in bench-scale tests, but the tests also revealed two problems with the commercial catalyst used. These must be solved before the process can be considered economically viable. The first problem involves mechanical integrity—too much of the catalyst broke up and was lost in the system. The second, involving chemical deactivation, or "poisoning," of the catalyst, is more complex. Carbon monoxide can react with various metals present in the reaction system to form compounds called carbonyls. The formation of carbonyls prevents the catalyst from taking part in the series of chemical reactions that unite carbon monoxide and hydrogen to produce methanol. It is believed that carbonyl formation was responsible for deactivation in the bench-scale tests. This problem could be resolved by appropriate design measures.

For unshifted once-through synthesis to work at its best, a catalyst must be found that can withstand the mechanical rigors of the fluidized-bed reactor and survive exposure to twice the amount of carbon monoxide found in shifted systems. EPRI has funded research at United Catalysts, Inc., to develop a new catalyst with the necessary properties.

"We've made a lot of progress," says Howard Lebowitz, manager of the Clean Liquid and Solid Fuels Program. "Recent tests have been very encouraging. Researchers feel confident," he reports, "that the physical attrition problem can be solved in time for the new catalyst to be used in a proposed pilot plant, while carbonyl formation problems appear likely to be overcome by the proper design changes. The results achieved to date have not been as good as would be required for commercial use," Lebowitz concludes, "but we believe we understand why. EPRI, in partnership with DOE, Air Products and Chemicals, Inc., Chem Systems, and Fluor Engineers and Constructors, Inc., is continuing research to determine whether the process is indeed viable."

Integration with GCC

Coproduction of methanol and electricity appears to be a promising way to reap the maximum benefit from an already attractive new technology—the coal gasification–combined-cycle power plant. Such plants produce very clean combustible gases from coal, then use a combined cycle of gas and steam turbines to generate power with very high energy efficiency. EPRI analyses indicate that GCC technology could prove cost-competitive with conventional coal plants that are equipped with flue gas desulfurization devices based on existing federal standards. Where environmental control requirements on coal are more stringent than the federal standards, as they already are in many regions of the United States, the incremental costs of GCC plants might even now be less than those associated with equivalent baseload power stations that use conventional pulverized-coal technology.

To integrate methanol production into a GCC plant involves placing the methanol synthesis reactor between the gasification system and the gas turbines. One of the GCC systems being developed with EPRI sponsorship employs a Texaco gasifier that uses limited amounts of oxygen to partially oxidize coal, producing a hot fuel gas. The major components in this fuel gas are combustible hydrogen and carbon monoxide. Removing some of the combustible gases from this stream to produce methanol would lower the net power output of the plant by about one-quarter, but the value of the methanol produced would more than compensate for the loss because methanol can replace the expensive oil used in peaking and intermediate-load generators. Just how much savings could be realized was the subject of a detailed economic evaluation Fluor performed for EPRI (AP-2212). Two cases were chosen for study, each based on a large GCC power plant with parallel trains of Texaco gasifiers that would consume a total of 10,000 t/d of coal; an initial operating date of 1990 was assumed. The first case involved no methanol production and resulted in power generating capacity of 1107 MW for the plant. In the second case, addition of the Chem Systems once-through synthesis process resulted in net power generation of 810 MW and coproduction of 2283 t/d of methanol. The cost of the coproduction plant was then scaled up to reflect production levels of 1107 MW of electricity and 3120 t/d of methanol.

To estimate the cost of methanol production, the revenue required for producing electricity in the plant used only to generate power was first calculated. This revenue was then subtracted from the total revenue required for electricity and methanol in the scaled-up coproduction plant. The balance was the revenue needed for methanol production—about $4.30 per million Btu (levelized mid-1980 dollars). The study concludes: "The potential benefits to the utility industry of coproducing 'once-through' methanol and electricity could be extremely large." Of course, the value of GCC plants must be demonstrated to the utility industry before the added complexity of a methanol coproduction plant can be seriously considered.

Future directions

So far, the Chem Systems methanol synthesis reactor has only been tested as a bench-scale unit, equivalent to production rates of between 0.25 and 0.5 t/d. Plans are now under way to scale up the system for testing in a 5-t/d pilot plant to be built in La Porte, Texas. This pilot plant, now in the construction phase, is a joint project of EPRI, Chem Systems, Fluor, Air Products, and DOE. Such a plant would still be much smaller than the hypothetical, commercial-size plant used as the basis for the Fluor study, which would produce 2389 t/d of methanol in a total of five parallel reactor trains.

To demonstrate the economic attractiveness of methanol coproduction will thus require integrating a large reactor with a commercial-scale GCC plant. The first such GCC plant is now scheduled to begin operation at the Southern California Edison Co. Cool Water station in 1984. This 100-MW demonstration plant might serve as a site for coproduction of methanol; however, no firm plans have been made to conduct such a test at Cool Water. There are other potential sites (TVA's Muscle Shoals plant, for example) that could at least be considered for demonstrating the scale-up of the Chem Systems process. Meanwhile, further evaluations are being made of how methanol coproduction might be incorporated into utility system expansion plans, including the possibility of selling the product to other users.

If the remaining technologic hurdles are surmounted and the economic advantages of methanol coproduction are verified by further tests, the impact on the utility industry could prove substantial. "Coproduction could provide a secure supply of highest-quality liquid fuel at a cost that is less than the market price for the next-highest-quality liquid fuel [distillate oil]," says Bert Louks, project manager in charge of the economic evaluation of coproduction. By the end of this decade, GCC plants are expected to become an important factor in new baseload generation. "Adding methanol synthesis reactors to such plants," Louks continues, "might alleviate concern over the quality, supply, and cost of liquid fuel." ■

This article was written by John Douglas, science writer. Technical background information was provided by Howard Lebowitz and Bert Louks, Advanced Power Systems Division.

Alvin Weinberg: Forty Years a Futurist

Overlapping careers in nuclear reactor physics, R&D administration, and science information tell him that our technologic and societal processes are the joint unfolding of a unified science. Now a member of EPRI's Advisory Council, Weinberg foresees more widespread electrification and longer-lived nuclear power plants.

Alvin Weinberg is tantalized by the prospect. "Electricity could be a force for economic recovery," he says. "It's such an important factor in productivity." Weinberg has been sitting in a joint meeting of EPRI's Advisory Council—of which he is a member—and its Board of Directors, and he is still turning it over in his mind.

"We were considering the whole issue of the role of electricity," he goes on, "the aims of utilities, the problems we all face. As a matter of national interest, there's every reason to move heavily toward electrification. But so many utilities are in no position to expand their capacity. There's a tension between what seems to be the utilities' responsibility to society and their responsibility to shareholders and ratepayers."

Weinberg's animation on the point is difficult to reconcile with the reserve one might presuppose of an internationally eminent nuclear scientist and longtime federal administrator. But Weinberg refreshingly contradicts stereotypes, not only in what he has to say but in how he says it and how he came to his career.

Science was his decision at about age 12, Weinberg recalls, adding that he thought then of becoming a chemist. A Chicago native, he went to the University of Chicago, graduating in 1935 with a joint degree in physics and biophysics and by then intending to work in biophysics. Adding MS and PhD degrees in physics, Weinberg was a university research associate in mathematical biophysics when the winds of war turned him from his path.

"My professor, Carl Eckart [later renowned as a marine geophysicist], asked me to work with him for six months, half time, trying to show that nuclear energy wouldn't work—and said I could then go on to something else. That was 1940–1941, and that six months became a life work."

Today, somewhat toward the other end of that life work, Weinberg looks back on 5 years with the wartime Manhattan Engineering District, 28 years (18 of them as director) at the Oak Ridge National Laboratory that sprang from it, and after a year in Washington, 8 years as director of the Institute for Energy Analysis (IEA), which he helped establish within the Oak Ridge Associated Universities.

Weinberg agrees that the specifics of that experience are partly what bring him to his EPRI advisory role. "I've been in the energy business for a long time. I've had a short stay in Washington, and I have some insights from our work at IEA." These experiences strengthen his conviction about nationwide electrification. They also account for his worry about more than the obvious economic impasse of utilities. "Among some energy policy intellectuals," he goes on, "there is an onslaught against electricity as an energy vector." Weinberg is explicit: "They just don't like electricity. And the reasons are that it is centralized and also it is nuclear."

Relaxing a bit, Weinberg expresses the hope that through EPRI he can encourage a truly serious response to this thinking. "You have to listen to the concerns these people are voicing. You can't just brush them off. You have to examine what they say and come to some judicious resolution."

Alvin Weinberg's technical convictions thus go hand in hand with a recognition that their realization depends as much on the people in an organization as on the atoms in a lattice.

Guidance along two paths

At first, though, it was all atoms in a lattice, and what Weinberg counts as the single most exciting passage of his professional life came in the first two years. Associated with Enrico Fermi and Eugene Wigner in what was called the Metallurgical Laboratory at the University of Chicago, he shared in the achievement of the first controlled nuclear chain reaction on December 2, 1942.

Three years later Weinberg's atomic energy research moved to Oak Ridge, Tennessee, the wartime secret site of U.S. production facilities for enriched uranium. Weinberg was already working for Wigner, who was the chief theorist of Fermi's Met Lab team, and Wigner became director of what was then known as Clinton Laboratories. By the time Wigner returned to his Princeton University faculty post in 1947, Weinberg was director of the physics division at Clinton, and by the end of 1948 he was research director of the newly named Oak Ridge National Laboratory. Seven years later he was appointed director of the laboratory, a post he held until the end of 1973.

Although only 13 years Weinberg's senior, Wigner was a strong influence. "I learned more from him, really, than from anybody else," says Weinberg. "He is a man of enormous breadth, commanding so much in mathematics, physics, chemistry, and engineering." In an unabashed compliment to his mentor, Weinberg adds, "It was natural that I acquired a rather broad interest in lots of things."

But it was in leadership that Wigner was the most important model. "He asked me to direct the physics division, and that's how I entered what became an administrative path. Much influenced by his style even here, I tried to keep in very close contact with details of the science and the engineering."

Some of Weinberg's most focused work in nuclear science was built on methods of analysis originally devised by Wigner. This had to do with what are called neutron distributions, the complex of relationships that determine the course of a chain reaction and—all-important in a power reactor—the pattern of heat production. The two men in 1958 were joint authors of what was for years the definitive theoretical book for reactor design.

But if Wigner was such an effective model, as Weinberg himself declares, it is likely that Weinberg was especially receptive because of an even earlier association, in his college years, with his own brother-in-law.

"Irving Goleman was older than I by a good deal, a professor of English and religion at the College of the Pacific for a long time," Weinberg recalls, "and he encouraged my interest in social questions. As a result, I read widely in those days and on broad issues. This was in the 1930s; but you know, things that happen early in your life never quite get away from you."

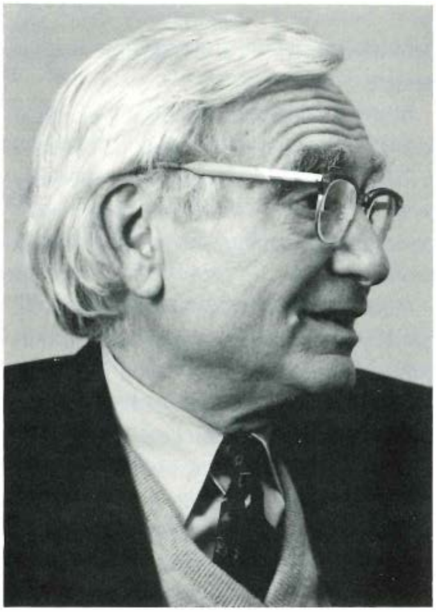
Wigner, the professor of physics, and Goleman, the professor of religion, thus were the influences that ultimately carried Weinberg to national prominence as a scientific spokesman and adviser well beyond the company of his professional associates.

Synthesis of a side career

Perhaps the watershed opportunity for Weinberg came late in 1959, when he was appointed to a three-year membership on the president's Scientific Advisory Committee. In this capacity, beginning in 1961, he chaired a panel on science information. This assignment took him briefly to Washington, where he spent the summer of 1962 at the White House, preparing a report titled "Science, Government, and Information," which was issued early the following year.

Though not an expression of Weinberg's views alone, the report acknowledged and discussed many problems about the growth of scientific enterprise in overall size, complexity, and consequent volume of information output.

One example, close to home for Weinberg, was the power of big-budget institutions (government and otherwise) to



"Nuclear technology suffers from growing pains. It is very young, barely one generation. It's not like automobiles, which are built by the millions every year and for which improvement therefore goes much faster."

dominate entire areas of science. A disconcerting side effect of this is the blurring of the line between scientific reportage and publicity claims as publicly funded science bids for continued support. And a further consequence is the attenuation of small, spontaneous science as the resources of money, manpower, and motivation are preempted by large institutional endeavors.

A particular concern to Weinberg was the potential loss of a unified science because of the individual scientist's sheer inability to assimilate even the major developments. In this connection, he saw the need to establish scientific information centers—institutes that synthesize new developments from assessments and analyses of existing data, rather than from original hands-on research.

The Weinberg report (as it came to be known) had a large and long-lasting influence on the field of science information. The idea of information centers catalyzed professional thought; the report was widely cited and translated into several languages. "People still come up to me 20 years later," he says, "and ask, 'Well, what do you think about science information?' So you see, I've had sort of a side career in the information business."

There are other expressions of Weinberg's interest in the long-term course and application of scientific inquiry. One was his writings for the journal *Minerva* in the 1960s. Another was his brief return to Washington, D.C., in 1974 to head the office of energy R&D in John Sawhill's Federal Energy Administration (FEA). Most important has been Weinberg's work at IEA.

Minerva began in 1962; its editor, Edward Shils, sought to improve understanding of the relationships between government and science. This, Shils felt, would "make scientific and academic policy more reasonable and realistic." Weinberg's early contributions dealt with scientific choice, as he says, "how you choose among competing areas of research when your total budget is limited." At issue were the relative merits of such endeavors as molecular biology, high-energy physics, nuclear energy, manned space exploration, and the behavioral sciences. Weinberg's philosophic approach involved internal criteria (the readiness of a field, the quality of its investigators) and external criteria (society's need or desire for its exploitation). He also addressed the still larger policy issue of allocating public resources between science as a whole and the other programs of government.

"Lo and behold," Weinberg says today, "those articles got to be very popular and started a whole subculture of people who would argue about those things. Also," he adds, "as had happened after the [Weinberg] report came out, people who encountered my writings on scientific choice were surprised that I was the same Weinberg who was involved in the design of reactors."

Many issues, many choices

Weinberg's responsibilities with the FEA fit into the same pattern of inquiry: energy R&D policies and the plans to implement them, the merit of specific energy programs, and the consistency of R&D priorities with overall policy. Options and issues went from the short term to the long and from the specific to the general: energy conservation, oil production, coal utilization, the breeder reactor, energy-environment trade-offs, industrial energy efficiency. Weinberg had already laid plans in Oak Ridge for IEA, which he was to direct, so Washington became a specific contract. "I agreed to come for a term of 365 days. I had a calendar, I crossed off each day, and 347 days is how long I stayed."

Weinberg's concern with the whole of science—that it *is* a whole and must be seen and treated accordingly—is at the root of his interest in how scientific efforts are directed, managed, and communicated. But even more inclusively, he sees life as a whole, and he has for years urged equal time for the technologic components and possible solutions of what are often seen solely as political, cultural, or societal problems—for example, population, food, pollution, and energy.

Highly placed encouragement and quiet support for these convictions helped Weinberg lay the groundwork for IEA even while he was still director of the Oak Ridge National Laboratory. IEA is a part of Oak Ridge Associated Universities, largely an R&D organization sponsored by 51 universities to encourage interaction between their faculties and the scientific resources of Oak Ridge. ORAU dates from 1946, a time when the national laboratory was both unique and underused, and when universities (mostly those in the south) were seeking to improve their scientific capability and appeal. Weinberg calls IEA "a think tank concerned with energy, but in a broad sense that leads to other issues, environmental matters like carbon dioxide, even cancer."

The context and motivation of U.S. electric power research, therefore, mean much to Weinberg and ensure his interest in his Advisory Council role. The Council's purpose, in fact, is to draw expression from people outside the utility industry. The range of perceptions by individuals from many vocational, institutional, and cultural segments of U.S. society become valuable clues and caveats for EPRI's management and technical staff. Weinberg joins labor leaders, educators, economists, lawyers, public utility commissioners, and public health and environmental experts in commenting on the work of EPRI.

Of course, the Institute and its people are not strangers to Weinberg. "Chauncey Starr [EPRI's founding president and now a vice chairman] is an old friend. He spent six months at Oak Ridge in the early days, and he was my neighbor, lived across the street." Even more pointed, Floyd Culler, who succeeded Starr at EPRI five years ago, came from a 33-year career at Oak Ridge; so, as Weinberg says, "Floyd and I are associates from way back. I was his boss for a long time."

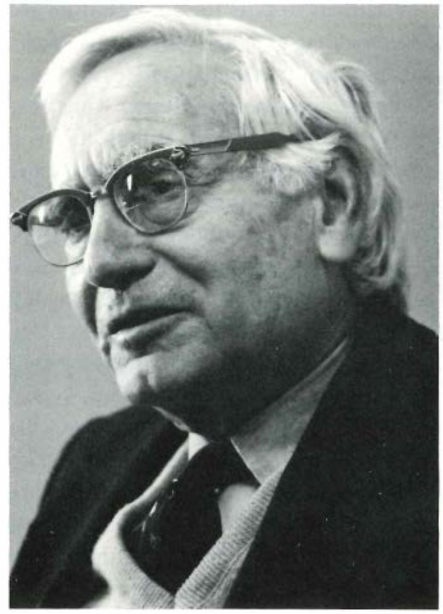
Fixing nuclear technology

Public science more often than not is big science, and public decisions are necessary in shaping the policy and course of that science. But we often fail to recognize that our opinions, attitudes, and values—the social components of scientific problems—are among the hardest facts of those problems. Weinberg sees this, just as he sees the technical components of societal problems. His perspective suggests that they are opposite sides of the same coin; that is, the exclusive labels are specious.

Weinberg's analyses are generally accepted by his audiences, readers, research sponsors, advisory clients, and most, but not all, of his technical peers. Combined with his candor and mode of expression, his statements have sometimes caused him to be seen (in an image he chooses) as a Cassandra of the nuclear business.

"Cassandra," he goes on to explain, "lived in Greek mythology. Given the gift of prophecy by Apollo, she later was the victim of his curse: that nobody would believe her."

The metaphor is ironic, because Weinberg considers himself a technology optimist, and he is agreeable about being regarded as pro-nuclear. But despite the time he has spent in nuclear energy—"longer than almost anybody else who is still in it"—he realizes that on the time scale of history "it is still a new thing that we're involved in, and it's not true that there is no possibility of anything bad happening."



"If I had it to do by myself, I'd adopt an energy policy for the United States much more like that of France; that is, move very aggressively toward electrification."

Weinberg recalls the reception he got in a meeting some five years ago for forecasting a utility reactor accident and concluding, "Even though nobody is hurt, the utility will go bankrupt and all hell will break loose. Utility people in the meeting were quick to say 'It'll never happen.' That's what I mean about Cassandra."

In a classic sense also, prophecy is more a matter of seeing and declaring reality than of trying to predict futures. The latter is a by-product of the prophet's awareness of human psychology. Of the accident that turned out to be Three Mile Island, Weinberg says simply, "Statistics showed that something like it would happen." As for the economic and social outcomes, he drew on his well-developed sense of human responses.

More than pro-nuclear, Weinberg would prefer to be seen as pro-energy, but energy at a low price. Of today's situation he observes, "Business always said that if the price was right, the problem would go away. And as the price of energy has gone up, people have adjusted." He insists, however, that something has been lost in the process because "if energy is expensive, then you must put more of society's resources into energy and less into something else. I think we should continue to try and get energy to be cheap."

Weinberg does not think energy is ultimately limited in any practical sense that makes it inherently expensive. Neither does he see a quick turnaround. "Eventually, but probably not in my lifetime, energy will get to be much cheaper than it is now. I'm thinking of electricity. And of course, I think of it in terms of nuclear energy."

How this can, may, or will come to pass brings Weinberg's well-grounded technical optimism to the fore. Right now nuclear energy costs are indeed inflated, he concedes ("at least, in this country"). But he considers it quite possible that today's plants will last not for their designed span of 25 or 30 years "but for 50 or 60 or 80 years, and by that time the sunk costs will have been amortized."

Capacity factors, Weinberg points out, increase as plants grow older; the annual ratio of actual to maximum energy production goes up, and this gives him confidence. As for specific problems with steam generators, piping cracks, pressure vessel embrittlement, and so forth, Weinberg acknowledges that "nuclear technology suffers from growing pains. It is very young, barely one generation. It's not like automobiles, which are built by the millions every year and for which improvement therefore goes much faster."

Fixing power institutions

Much, but not all, the solution lies in what Weinberg calls the technological fix, a term he recalls coining in a paper some 15 years ago. But he adds that "fixes are going to include institutional fixes as well, and EPRI is a fine example, as are NSAC and INPO." The Nuclear Safety Analysis Center, now a part of EPRI, was established right after Three Mile Island to probe that accident and go on to generic safety problems. The Institute of Nuclear Power Operations is a separate, utility-supported center for developing improved plant operating routines and training utility plant personnel.

Institutional fixes, the social counterpart of the technical, are just as important for Weinberg. "If I were to criticize the utility industry, it would be about the way it is structured: 3000 utilities, and more than 200 of them pretty large generating entities. It seems kind of crazy to have even as many as 200 separate organizations for generating electricity from the relatively few huge plants that are spread among them."

Weinberg is on record with the concept of dedicated generation "parks," independently owned and operated, as a possible solution for nuclear power management. "The pragmatic and practical way to deal with this fragmented structure," he says, "is to set up entities that will somehow impose the kind of integration that is needed."

Asked his view of an ideal approach, Weinberg responds, "If I had it to do by myself, I'd adopt an energy policy for the United States much more like that of France; that is, move very aggressively toward electrification." France, he acknowledges, has some important institutions already in place, "a more centralized political structure and a more centralized electric utility structure—they have only one electric utility."

In this country, Weinberg sees joint agreements for power plant construction and ownership as the nearest approximation of the French pattern. "Each utility achieves some of the economies of scale without the sole financial or other commitments."

Along with his optimism and his idealism, whether technical or social, Weinberg injects a caveat, a disclaimer, a note of another reality. "France is making a big gamble, of course, with all those nuclear power plants. A political gamble and a financial gamble. My guess is that France will be blessed with cheap energy 20–30 years from now, the cheapest electric energy in Europe. But all this assumes that the plants work as people hope. It may be that they won't; then it will be tough."

A futurist makes many projections of cause and effect, considers many alternative outcomes. A prophet proclaims reality. Weinberg is both. It may be that he is a good prophet simply because, as a competent futurist, he covers all the bases. ■

This article was written by Ralph Whitaker and is based on an interview with Alvin Weinberg.

DOE Enriches the Nuclear Option

DOE's assistant secretary for nuclear energy describes how the agency is responding to the Reagan nuclear energy policy.

Shelby T. Brewer was involved in the nuclear field for many years before he was appointed to the nuclear energy program at DOE. His career began in the early 1960s when he served in the U.S. Navy and continued while he was on the staff of the Massachusetts Institute of Technology. He also worked as a consulting engineer for Stone & Webster Engineering Corp., the U.S. Atomic Energy Commission, and the Energy Research and Development Administration. In his current position at DOE, Brewer oversees all reactor (breeder and converter) development and demonstration programs, including fuel cycle research, enriched-fuel production for domestic and foreign markets, naval reactor development and prototype operation, and such unique applications of nuclear energy as power isotopes and reactors for space missions.

In a recent interview, EPRI's Washington Report correspondent asked Brewer to provide an update on DOE's nuclear program.

How is the Office of Nuclear Energy structured?

When I became the assistant secretary in 1981, I reorganized the nuclear energy office to improve management and provide a better flow of authority and responsibility within the program. I removed the multiple tiers of responsibility that had previously existed in order to separate the priority functions, thereby providing direct accountability for each of the president's policy initiatives. For example, there are now separate offices assigned to licensing reform, breeder programs, uranium enrichment, reprocessing, and the fuel cycle. I believe this revised alignment is more conducive to fulfilling policy objectives.

As directed by the president, DOE has submitted nuclear licensing and regulatory reform initiatives to Congress. What is contained in this legislative proposal and do you anticipate its passage this session?

The legislation, which was submitted to Congress on March 18, contains five major elements: preapproval of designs and early approval of sites for nuclear power plants, a one-step process for issuing construction licenses, a similarly expedited process for issuing operating licenses, a revised Nuclear Regulatory Commission hearing format, and provisions for the way in which NRC requires retrofits. We believe that the complexity of the current regulatory and licensing process hinders that which it is meant to ensure—greater safety—and has had a detrimental impact on the economics of nuclear energy because of the long lead times involved. To attract investors, utilities must have assurance that a plant will be on-line and generating power by a specified date. The basic intent of the legislation is to create a more rational and predictable licensing and regulatory process, with a more effective focus on safety issues. We hope to have congressional action on the bill later this spring and are aiming toward its passage in the 98th Congress.

DOE was given additional responsibility by Congress in the area of light water reactor safety research. What activities does DOE plan in this area and will they have an effect on international cooperation?

One of our roles is to coordinate the light water reactor safety research efforts of various parties, such as NRC, EPRI, the Institute of Nuclear Power Operations, and private industry. In terms of our own program, we have recently concluded an international agreement to support an extensive safety testing program at the loss-of-fluid test (LOFT) facility for the next three years. In the facility, which is located in Idaho, is an experimental pressurized water reactor designed to simulate loss-of-coolant and other potential nuclear-related accidents. In addition to the United States, participants in the $91 million project are members of the Organization for Economic Cooperation and Development—Australia, Finland, the Federal Republic of Germany, Italy, Japan, Sweden, Switzerland, and the United Kingdom. LOFT is a unique facility and will be the only one of its class in the world for at least the next four or five years. Its previous focus on U.S. safety and regulatory issues will now be expanded to include experimental research on operating procedures and the design of commercial reactors and their safety systems. Instead of the U.S. government funding the entire program, the costs will be shared by the countries in the consortium.

What is DOE doing in the breeder program?

Breeder reactors have the potential to extend our nuclear fuel capabilities some 100 times. They can transform the stockpiled uranium tailings left over from our uranium enrichment activities into an energy resource capable of providing the current level of total U.S. electric demand for 700 years. In fact, the energy equivalent of the breeder is more than that available from the total demonstrated U.S. coal reserves or from the world's proven reserves of oil. Despite these multiple benefits, however, breeder development had been stymied until the current administration came into power. Complementing the president's emphasis on breeder development as a potential long-term addition to U.S. energy security and recognizing the industry's inability to shoulder alone the inherent high cost and technical risks, I redirected our breeder efforts to stress an integrated program strategy of plant scale-up supported by test facilities and basic technology research. The Clinch River breeder reactor program was redirected and streamlined to accelerate construction and licensing approval. A recent interagency electric utility task force submitted a report to Congress on ways to increase private sector funding for the Clinch River reactor, concluding that the plant and the electricity that will be produced have substantial private investment value. Clinch River is one stage in the program that will lead, in the longer term, to a commercial-size breeder. With that in mind, we are currently working with EPRI to find an institutional and financial structure—probably involving major international collaboration—to design and develop a large breeder plant.

You mentioned the enormous uranium resources remaining from previous uranium enrichment activities. What is the current enrichment situation?

Over the last decade, the United States has lost the major share of the foreign market in sales of enriched uranium. In 1972 we had 100% of the total world market; now we have about 30%. This change is attributable to two factors. The first is that during 1973–1974 we accepted no new contracts for uranium enrichment; two companies (Urenco and Eurodif) and the USSR entered the market and swooped up a substantial portion. Then beginning in 1977, the Carter administration discouraged all aspects of nuclear development. As a result, the United States became known as an unreliable supplier of enriched uranium. More recently, we have even noticed some slight erosion in the U.S. domestic market. One factor is simply cost; because of our use of gaseous diffusion technology, which requires tremendous amounts of electric energy, the cost for our enrichment services is higher than for those of our European competitors. We are literally being priced out of the market.

What is DOE doing to stimulate U.S. uranium enrichment activities?

To reduce our dependence on costly gaseous diffusion technology, we are proceeding swiftly toward development of gas centrifuge technology and are constructing a very large facility, the gas centrifuge enrichment plant (GCEP), in Portsmouth, Ohio. When completed, this plant is expected to displace much of the gaseous diffusion capacity. Because gas centrifuge enrichment uses only about $\frac{1}{20}$ of the energy needed for gaseous diffusion, GCEP will enrich uranium at a much lower cost. To improve our pricing structure, I just appointed a task force of specialists to delve into the status of the

Brewer

uranium enrichment business nationally and internationally and to suggest ways to strengthen the U.S. role. The task force is composed of Manson Benedict, MIT professor emeritus; Lelan Sillin, retiring chairman of Northeast Utilities; John Simpson, former president of Westinghouse Electric Corp.; Manning Muntzing of the Doub and Muntzing law firm; and a fifth person, who will be a member of one of the "big eight" accounting firms.

What support does your office plan for the reprocessing of light water reactor fuel?

In his nuclear policy statement of 1981, the president directed DOE to identify barriers to reprocessing and to suggest ways to stimulate private sector involvement. Reprocessing has advantages that are clearly in the national interest. Because reprocessing separates the wastes from used fuel and saves the reusable uranium and plutonium, the recovery of this residual energy value can appreciably extend our uranium resources. Other benefits include the availability of the separated plutonium as a feedstock for our breeder development and demonstration program and the ability to convert the reprocessed waste (which only amounts to about 4% of the original weight of the spent fuel) into a compact, solid form particularly well suited for disposal. In spite of these advantages, it is doubtful that commercial reprocessing ventures will evolve without some kind of government stimulation. The best current option appears to be the completion and operation of the Barnwell, South Carolina, nuclear fuels plant. The current owners are not interested in further investment at Barnwell, so DOE, the nuclear utility industry, and the nuclear supply industry are seeking ways to operate it commercially. DOE's funding for our safeguards research program at Barnwell runs out on July 31, 1983.

What is the extent of DOE's activities in the breeder fuel cycle?

A breeder plant cannot stand alone unless it has a fuel cycle that includes fuel fabrication and reprocessing on the back end. With regard to fuel fabrication, we are constructing a pilot plant at Hanford [Washington]—the SAFE automated facility—which will fabricate fuel assemblies for the fast flux test facility and Clinch River. With regard to reprocessing, we are developing and testing equipment on a pilot scale in Oak Ridge.

Your office is involved in the Three Mile Island R&D Program. Would you explain a bit about the program's thrust?

The TMI program is a multiyear research program based on two statutory principles. First, our mandate under the 1954 Atomic Energy Act requires pursuing R&D of generic value to the nuclear option that could offer improved safety and reliability for all nuclear power plants. Second, we must fulfill our responsibility to handle and dispose of nuclear wastes. As a tangential benefit of our research program, DOE has already moved more than half of the TMI wastes out of Pennsylvania. In addition, we will be transporting the entire damaged reactor core to one of our R&D testing sites to learn more about the accident. The utility will fully reimburse the federal government for transporting and disposing of the core. The activities at TMI are being handled in accordance with a Memorandum of Understanding signed by DOE, EPRI, NRC, and General Public Utilities.

DOE, the National Aeronautics and Space Administration (NASA), and the Defense Advanced Research Projects Agency (DARPA) recently signed an

agreement to pursue ways to deploy nuclear reactor systems in space. Would you elaborate on what the agreement involves and its intent?

The program we are initiating, which is called SP-100, is a triagency program directed by a steering committee with members representing each agency. I am chairing the steering committee. The near-term objective (12–18 months) is to screen a number of possible space reactor types and configurations to determine which are best suited for civilian and military space missions. Questions relating to size, purpose, performance requirements, and physical attributes will be addressed. After about 18 months, we will enter the hardware development phase. At that point, DOE will develop the actual reactor and ground-test it. I am hopeful the reactor development will be completed this decade.

In light of decreasing oil prices and long construction lead times for nuclear plants, what role do you feel nuclear power will play in the future?

A major role. Even though we are currently experiencing low growth rates in electricity use, there will have to be additional generating capacity amounting to at least 400–500 GW in the next 20–25 years to meet energy demands. There are only two fuels capable of bearing that burden: coal and nuclear. As far as nuclear goes, we have the largest and most mature nuclear industry in the world. The major question that needs to be answered is when will utilities order more plants. If we stabilize the licensing process through our proposed legislation and if utility financial conditions improve, I think the potential exists for a resurgence of orders for nuclear plants in this decade. I become even more optimistic as the economy continues to recover.

Finally, what progress has DOE made in improving the climate for further nuclear power development?

We have a licensing reform package that can streamline the licensing and construction of nuclear plants. When implemented, these reforms will significantly reduce the current, unacceptable lead times for bringing a plant on-line and encourage renewal of investment in nuclear plants. We have new, landmark waste management legislation that creates the structure needed for resolving the nuclear waste issue. We are aggressively pursuing advanced breeder technology, including the accelerated construction of the Clinch River plant, and have identified ways to attract greater private sector financial support for Clinch River. We are continuing to seek ways to encourage reprocessing in the private sector. And we are applying realistic policies for nuclear exports and fuel cycle services to reestablish the United States as a reliable partner in international nuclear energy commerce. ■

This interview was conducted by Ellie Hollander, Washington Office.

Rate Design Study Nears Completion

Final phase will review the state of the art of demand-side research.

A cooperative nine-year effort by the electric utility industry to assess the potential of load management techniques for holding down the cost of service is nearing completion. In its fourth and final phase, the Electric Utility Rate Design Study (EURDS) will review and summarize the broad spectrum of demand-side research that has become a growing part of EPRI's overall R&D program.

Over 90 reports—ranging in topic from utility pricing methods to technologies for customer load control—have been produced during the course of EURDS, conducted by EPRI under joint sponsorship by the Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association. The study was the industry's response to a special request from the National Association of Regulatory Utility Commissioners (NARUC) in 1974 for an examination of strategies to mitigate the effects of rising fuel prices, inflation, and other economic factors on consumers' electric bills as these effects became apparent in the early 1970s.

The scope of EURDS has evolved over time to meet the needs of the utility and regulatory communities. In response to a recent NARUC request for extension of the study, the final phase will concentrate on synthesizing available information relating to the transferability of load and load response data among utilities and the link between customer attitudes and response to load management approaches.

The focus of the final phase reflects a recognition of the substantial research going on in these areas at EPRI, at other research organizations, and at individual utilities. The Rate Design Study Project Committee determined that the Phase IV studies should summarize and evaluate existing research and utility experience to date in load management. The objective is to provide reports that can be widely used by industry and regulatory personnel.

The first two phases of EURDS focused on the technologies for implementing time-of-day pricing of electricity, identification and evaluation of electronic methods for controlling electric energy use during peak demand periods, and the cost and feasibility of shifting some types of electricity consumption from peak to off-peak periods. The third phase of the study included a set of regional conferences and workshops on cost and rate factors of load management and the development of a workbook for calculating the cost-effectiveness of specific load management approaches.

As a result of the extensive research conducted for EURDS by numerous consultants, advisory groups, and other contributors, general conclusions have emerged regarding the potential effectiveness of load management in holding down the cost of electric service. The study found that time-of-use rates and direct load controls can induce customers to lower peak demand for electricity and shift peak-period use to off-peak periods.

Although such shifts or reductions in demand can in turn lower a utility's cost of delivering power, the actual benefits of specific load management policies depend heavily on the operating characteristics, customer loads, and service territory of individual utilities.

The study has shown that some methods are available for identifying the specific situations where particular load management programs are cost-effective, but again, these can vary in degree of certainty, depending on the utility and its customers. The importance of customer understanding and education as a condition to customer acceptance of load management programs was highlighted.

The final phase of EURDS is to be completed by the end of this year, but much of the end-use R&D begun under the program will continue in the form of individual research projects at EPRI in the Energy Analysis and Environment Division's Demand and Conservation Program. The work involves development of methods and tools to analyze and plan load management options, development of technology, and evaluation of communication systems related to load management. Specific projects at EPRI include a study of customer acceptance of direct load controls, development of load data transfer techniques, and a study of the transferability among utilities of residential time-of-use rates and the results of direct load control experiments. EURDS will be reviewing these and other ongoing projects in its closing phase. ■

Construction Lead Time Study

EPRI's Energy Resources Program has completed a two-year study of power plant construction lead times. Applying both qualitative and quantitative methods, the project examined the causes of construction delays and the potential for controlling delays in future plants. In particular, the research was developed to isolate causes of schedule slippage and to understand the forces behind recent changes in construction lead times.

Detailed case studies were used, not only to develop an understanding of the factors affecting lead times but also to form testable hypotheses about causal relationships and interactions. The research methodology, which applied quantitative methods to publicly available data, produced valuable insights into the major factors that have been causing delays.

Project Manager Stephen Chapel reports that construction lead times have remained stable for fossil fuel plants, and that lead times for nuclear plants now under construction are likely to be shorter than those for their immediate predecessors. Further, the study cautions that nuclear plants ordered in the 1980s could experience schedule delays and increased lead times if the regulatory process continues to impose retroactive design changes during construction.

In general, however, the research does not reveal a clear trend, suggesting that inferences about nuclear plant licensing requirements in the future are quite uncertain. To illustrate this conclusion, the study shows the dynamic effects of regulations, separates two populations of nuclear plants for which safety issues have had fundamentally different effects, and documents the downward trend in lead times for plants under construction, which have been shorter than past experience would indicate.

The average construction time for nuclear plants begun before 1972 increased about 5% per year. Construction of plants started during 1973 took an average of 10 years; significant out-of-scope work increases, resulting largely from regulatory design changes stimulated by the Calvert Cliffs decision and the Browns Ferry and Three Mile Island events, caused this increase. As the effects of the TMI accident and other industrywide shocks have subsided, lead times for nuclear plants currently under construction have begun to decline. The industry is learning to build plants that incorporate recent design changes; thus, except for delays imposed by utilities themselves, plants begun in the late 1970s will probably be completed in about 8 years.

In contrast, average coal plant construction lead times have not increased, except for extensions caused by financial problems and slowed utility load growth. Barring major effects from the 1977 amendments to the Clean Air Act, and assuming increased accuracy in load growth forecasts and fewer funding constraints, average construction time for coal power plants will probably show no increase. ■

Unexpected Dividends From TMI-2 Research

Utilities with pressurized water reactors could realize savings of $1.2 billion as a result of R&D work emerging from the Joint TMI-2 Information and Examination Program. Sponsors of the research are GPU-Nuclear, EPRI, the Nuclear Regulatory Commission, and the Department of Energy—collectively known as GEND.

The utility industry recognizes that the damaged TMI-2 unit can provide valuable technical and engineering information over and above that obtained in the normal plant cleanup and recovery operations. All participants expect to obtain information of lasting value. EPRI will use the technical input to address generic safety issues raised by the accident and to contribute to current programs in materials behavior, fuel performance, plant decontamination, and component qualification and survivability.

A report on EPRI's contribution to GEND is the source of the savings estimate (NP-2907-SR) and cites a number of program accomplishments. For example, investigators used available computer codes for theoretical analysis of the generation, release, escape, and dispersion of core debris during and after the accident. A comprehensive map of radioactivity in the auxiliary buildings also resulted from the work performed in 1982.

In another project, which evaluated chemical decontamination methods, analysts thoroughly reviewed historical postaccident chemical decontamination methods, analyzed their relative effectiveness, and discussed associated problems. They then evaluated and compared the effectiveness and impact of 14 potentially useful chemical decontamination processes. In related work, 17 nonchemical decontamination methods were identified, and their prior applications and specific advantages and disadvantages were described. Analysts rated the methods according to their suitability for application to TMI-2 cooling systems.

EPRI also funded plans for examination, decontamination, repair, and requalification of the reactor building polar crane and is developing generic requalification procedures, using the TMI-2 primary pressure boundary as an example. ■

Utilities Submit AFBC Proposals

Five electric utilities have submitted proposals to EPRI offering to cosponsor and host a 100–200-MW (e) demonstration power plant to test the feasibility of using atmospheric fluidized-bed combustion (AFBC) on a commercial scale. Kurt Yeager, director of EPRI's Coal Combustion Systems Division, said the proposals will be carefully evaluated before a decision is made on the construction and operation of one or more demonstration plants.

The utilities that have submitted proposals in response to EPRI's solicitation are Cleveland Electric Illuminating Co. of Cleveland, Ohio; Colorado Ute Electric Association, Inc., of Montrose, Colorado; Northern States Power Co. of Minneapolis, Minnesota; Puget Sound Power & Light Co. of Bellevue, Washington; and the Tennessee Valley Authority of Knoxville, Tennessee, in a joint response with the state of Kentucky and Duke Power Co. of Charlotte, North Carolina.

AFBC shows promise of providing electric utilities with a clean and economic way to burn various grades of coal, including high-sulfur coals commonly found in the eastern United States. In a fluidized-bed boiler, coal is scattered onto a limestone bed that is suspended in air forced from the bottom at atmospheric pressure. This causes the limestone particles to percolate like a liquid on top of the layer and gives rise to the term *fluidized-bed.*

Testing of the AFBC process is currently under way at TVA's $68 million, 20-MW (e) pilot plant located at the Shawnee Steam Plant Reservation near Paducah, Kentucky. EPRI is funding $18.5 million of a $28.5 million test program that is expected to be completed by mid 1986.

Yeager said design and construction of the proposed commercial-scale plant will begin after the host utility has been selected. If testing of the AFBC process at this size proves successful in the late 1980s, the nation's electric utilities would have the option of building a new generation of power plants in the 1990s that could burn coal more efficiently and produce fewer emissions than existing coal-fired plants.

Because the fluidized-bed process produces lower amounts of sulfur dioxide and oxides of nitrogen, Yeager points out, the installation of costly, add-on scrubbers could be eliminated at great savings to the electric power industry and its customers. Scrubbers can add as much as 50% to the cost of building a new conventional coal-fired plant, according to Yeager.

Lower operating temperatures also contribute to improved plant performance and reliability. Fluidized-bed boilers operate at temperatures far below the point at which coal ash melts. Thus, the ash slagging and fouling that plague pulverized-coal and stoker-fired furnaces can be eliminated. The ash can be easily removed during the combustion process. ■

CALENDAR

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

JULY

12–14
Seminar: Equipment Qualification
Los Angeles, California
Contact: Robert Kubik (415) 855-8905

12–15
Annual Review: Demand and Conservation Research
Denver, Colorado
Contact: John Chamberlin (415) 855-2750

14–15
Seminar: Simulation of Power System Load and Generation
San Francisco, California
Contact: Jerry Delson (415) 855-2619

AUGUST

2–3
Seminar: Decision Framework for Air Quality Standards
Washington, D.C.
Contact: Dennis Fromholzer (415) 855-2741

9–11
Seminar: Equipment Qualification
Portland, Oregon
Contact: Robert Kubik (415) 855-8905

SEPTEMBER

13–15
Seminar: Equipment Qualification
Dallas, Texas
Contact: Robert Kubik (415) 855-8905

19
Seminar: Decision Analysis for Fuel Planning
Washington, D.C.
Contact: Stephen Chapel (415) 855-2608

R&D Status Report
ADVANCED POWER SYSTEMS DIVISION

Dwain Spencer, Director

H-COAL DEMONSTRATION

Demonstration of the H-Coal liquefaction process was completed in November 1982 at the H-Coal pilot plant in Catlettsburg, Kentucky. The goal of this project, which was begun in 1974, has been to make the H-Coal technology commercially ready.

Results achieved during extended operation with high-sulfur Illinois basin bituminous coals and a representative low-sulfur western subbituminous coal have demonstrated this process's commercial readiness. The basic process was demonstrated by 290 days of operation, during which 56,500 tons of coal were processed. Stable reactor operation was achieved for extended periods. The demonstration also confirmed prediction of steady-state reactor product yield performance at the design catalyst addition rate. Table 1 compares pilot plant and process development unit (PDU) yields achieved with two major coal types. Operating data obtained from individual units were sufficient to predict or guide commercial scale-up. Mechanical design and equipment were significantly modified during the program to secure more stable, reliable plant performance. Subsequent performance evaluation of the modified system resulted in the conclusion that sound mechanical and process designs could be realized for commercial application.

The final 98-day run achieved significant results in many important areas. It confirmed multipass, fired, slurry heater viability. The multipass heater was used successfully for the entire 98 days. Problems with segmental wedge flowmeters were overcome by improved design and maintenance procedures. The operation determined maintenance requirements for high-pressure slurry feed pumps operated at commercial piston speed. Acceptable service was achieved by alternating between two pumps.

Operation of the coal feed, slurry mix tank at 450°F (232°C) confirmed this important commercial design point. Extended operation at 430°F (221°C) was achieved without difficulty; the operating temperature was limited only by heat losses. Two high-stage and one low-stage slurry control valves were changed during the run. Valve trim life of well over a month is now anticipated. Valves of different design produced by several manufacturers have been found satisfactory. There were no slurry block valve failures.

Performance and yields were evaluated while using high-chloride Kentucky No. 9 coal at design conditions for 18 days. Material balances were obtained and product yields on two coals were determined at steady-state conditions with catalyst addition and withdrawal. Performance characteristics were determined for the coal-grinding system. Ground-coal size distribution and heat and material balances were obtained over a wide range of coal feed rates.

Difficulties with conventional coal weigh feeder belts prompted a search for an alternative metering device. A controllable rapid batch gravity device was found to be highly accurate. The equipment tested demonstrated high accuracy but would require hardening and weatherproofing for process application.

The waste treatment plant was operated above design hydraulic loading without difficulty. The suspended solids concentration in the effluent was higher than the design level because of settling problems in the biological unit. These problems were attributed to higher-than-expected phenol content of feed.

A full-scale H-Coal plant will require a hydrogen source. The major portion of hydrogen is expected to be produced by gasification of the nondistillable, ash-containing, vacuum-flashed H-Coal product. Because hydrogen for the pilot plant was purchased, the hydrogen manufacturing step was not included in the H-Coal development program.

The plant will undergo extensive metallurgical inspection after shutdown for corrosion rack and weld evaluation. A second post-

Table 1
COMPARISON OF REACTOR YIELD SCALE-UP FOR TWO MAJOR COALS

	Bituminous			Subbituminous	
	Pilot Plant (250 t/d)	Pilot Plant (250 t/d)	PDU (3 t/d)	Pilot Plant (250 t/d)	PDU (3 t/d)
Run No.	8	11	5	10	10
Component (wt% dry coal)					
C_1–C_3	11.8	9.9	10.7	9.3	10.0
C_4–400°F (204°C)	22.5	18.5	18.7	26.0	22.1
400–650°F (204–343°C)	16.6	19.8	20.4	14.6	13.2
650–975°F (343–524°C)	8.9	9.5	8.0	9.3	10.9
Residuum and unconverted coal	24.7	25.6	24.8	19.8	22.0

demonstration objective is to evaluate process products. Most of the naphtha from the plant has been transferred to Ashland Oil, Inc., refineries. In addition, 9000 barrels of middle and heavy distillates were made available at shutdown for EPRI combustion tests at various utility sites.

Final disposition of the pilot plant facility has not been decided. Other liquefaction processes or H-Coal variations could be demonstrated in the existing plant at relatively modest cost. Ashland Oil has contracted with DOE to maintain the plant for the near future. *Subprogram Manager: Norman Stewart*

COAL-DERIVED RESIDUAL FUEL OIL COMBUSTION

EPRI's Power Generation Program develops information on the handling, combustion, and emissions properties of coal-derived synthetic fuels. One of the program's primary objectives is the application and use of synthetic fuels in all types of utility prime movers, including boilers, combustion turbines, and diesel engines. To achieve this objective and to provide feedback on product applicability, EPRI sponsored laboratory-scale boiler combustion tests of coal-derived residual fuel oil (RP1412-5). These tests, using some of the earliest products of advanced, two-stage liquefaction (TSL) processing carried out at EPRI's Advanced Coal Liquefaction Development Facility, Wilsonville, Alabama (RP1234), are the first step in assessing this synthetic liquid's potential as a substitute for petroleum-derived No. 6 fuel oil in utility boilers.

Only recently has very low sulfur No. 6–type residual fuel oil been derived from high-sulfur coal in quantities sufficient for even laboratory-scale boiler combustion tests. TSL residual fuel oil, a blend of distillable and nondistillable or residual components, may cost less and yield more fuel oil (60–65 wt% of the moisture- and ash-free coal is converted to fuel oil products) than obtained from those processes that produce only distillate products (40–45 wt%) and have been demonstrated recently at the large (250-t/d) pilot plant scale. In addition, TSL residual fuel oil can be directly substituted for petroleum-derived No. 6 fuel oil in oil-fired utility boilers. This ease of substitution contrasts sharply with pulverized solvent-refined coal (SRC-I) solids, which would require that oil-design boilers be retrofitted with such devices as pulverized-fuel handling systems and special burners. Despite these potential advantages, TSL residual fuel oil's high nitrogen content and lower hydrogen-to-carbon ratio, especially in the residual component boiling above 450°C (850°F), may produce higher NO_x and particulate emissions. In this respect, TSL residual fuel oil combustion is expected to be more closely related to that of either petroleum-derived residual fuel or pulverized SRC-I solids than coal-derived distillates. Therefore, it is important that TSL residual fuel oil combustion and emission characteristics be determined under conditions in which they may be compared with those of petroleum-derived No. 6 fuel oil before field tests in utility-scale equipment.

Drum quantities of TSL residual fuel oil were produced at EPRI's 6-t/d coal liquefaction pilot plant in Wilsonville, Alabama. Figure 1 shows a simple production flow sheet. In the decoupled, two-stage liquefaction operating mode, high-sulfur (~3.5%) bituminous coal is liquefied in a noncatalytic, or thermal, first-stage reactor, and the nondistillable residual product is de-ashed before it is processed in a second catalytic hydrotreating stage. The hydrotreating step results in both desulfurization of the first-stage residue (solid SRC-I at ambient temperature) and its partial conversion to distillable products. The lower-sulfur (0.2%) residual liquid is then blended with first-stage middle distillate and second-stage full-range distillate in essentially process yield proportions. A single-phase liquid residual fuel oil is a product of this operation. An earlier status report describes the TSL process more fully (*EPRI Journal,* June 1982, p. 41).

Table 2 compares the properties of three classes of coal-derived liquid fuels with those of a range of typical petroleum-derived No. 6 fuel oils. Coal-derived distillates from the H-Coal, Exxon Donor Solvent (EDS), and SRC-II processes are the highest-quality fuels in most respects. Except for its higher nitrogen, lower hydrogen, and exceptionally low vanadium content, TSL residual fuel oil is comparable to petroleum-derived No. 6

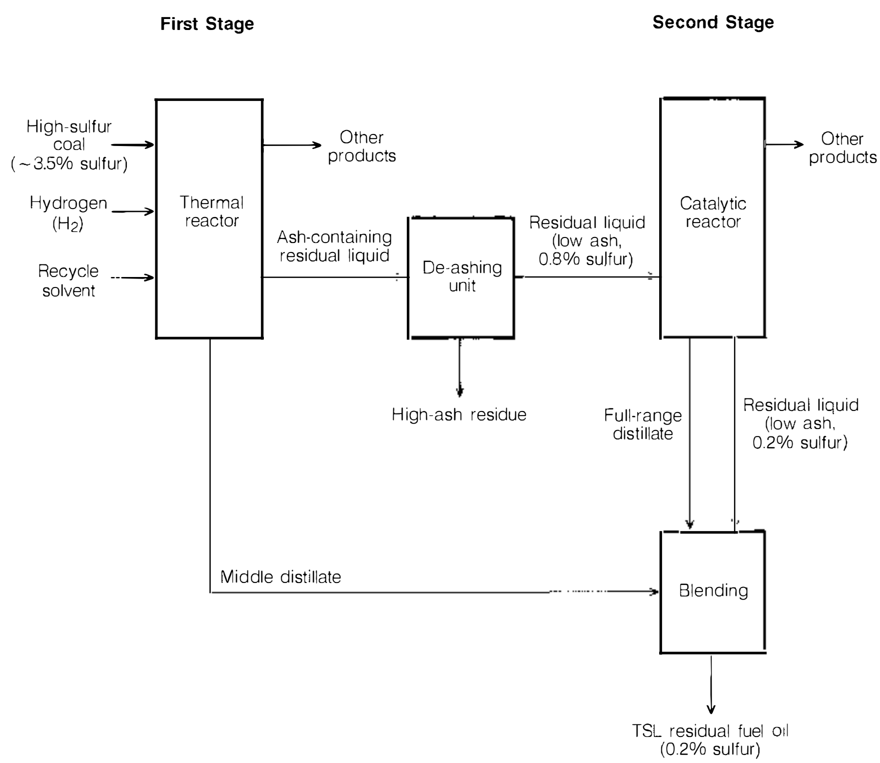


Figure 1 Production of two-stage liquefaction residual fuel oil. High-sulfur coal, gaseous hydrogen, and process-derived recycle solvent are reacted in the thermal stage, and the de-ashed residual product is further processed in the catalytic stage prior to blending with first-stage middle distillate.

fuel oil. SRC residual fuel oil, prepared from distillate and residual products of the single-stage solvent refining of coal, departs even more from No. 6 fuel oil, most notably in sulfur and nitrogen levels and in temperatures required for handling. No. 6 fuel oil typically requires 50°C (122°F) and 100°C (212°F) for pumping and atomizing, respectively.

KVB, Inc., conducted tests in a 3 × 10^6 Btu/h industrial boiler extensively modified to simulate utility boiler conditions. The TSL residual fuel oil burned well with a flame indistinguishable from that of No. 6 fuel oil under both rich/lean staged and unstaged combustion conditions. The fuel handled well and can be atomized under conditions comparable to those for petroleum-derived No. 6 fuel oil.

Table 3 compares TSL residual fuel oil particulate and NO_x emissions with those from No. 6 fuel oil and several distillate coal liquids. Unstaged combustion using the standard atomizer resulted in NO_x levels about 70% higher than those that result from burning No. 6 oil. This phenomenon was expected because the residual coal liquid has a higher fuel nitrogen content. All distillate coal liquids produced NO_x emissions consistent with their respective fuel nitrogen contents. Particulate emissions were consistent with the fuel ash levels—the distillates having the lowest and the TSL residual fuel oil the highest.

Staging permitted considerable reduction in NO_x emissions for all fuels. However, staged combustion more than doubled particulate emissions for TSL residual fuel oil, which indicates that carbon burnout is a problem for this fuel. Attempts to reduce particulate emissions under staged conditions by adjusting the burner settings were largely unsuccessful. However, atomizer modification significantly reduced NO_x to levels comparable to the 0.5 lb/10^6 Btu (~375 ppm) New Source Performance Standard for coal liquids, while achieving a relatively low level (0.086 lb/10^6 Btu; ~65 ppm) of particulate emissions. This result suggests that burners may be adjusted for an acceptable trade-off between particulate and NO_x emissions. More work to establish optimal burning strategy for fuel flexibility should be carried out if these fuels become available as substitutes for petroleum-derived boiler fuels. *Subprogram Manager: William C. Rovesti*

Table 2
PROPERTIES OF SYNTHETIC AND PETROLEUM-DERIVED FUEL

Fuel Property	Coal-Derived Synthetic Fuel: Full-Range Distillates	SRC Residual Fuel Oil	TSL Residual Fuel Oil	Petroleum-Derived No. 6 Fuel Oils
Heat of combustion (Btu/lb)	17,000–18,000	16,900	17,400	17,500–18,500
Constituent (wt%)				
Hydrogen	8.8–10.5	7.5	8.5	9.5–12
Nitrogen	0.2–1.0	1.2	0.9	0.2–0.8
Sulfur	0.02–0.3	0.9	0.2	0.3–3.5
Ash	0.01–0.03	0.07	0.05	0.01–0.5
Vanadium (ppm)	<1	<10	<5	10–200
Pour point °C (°F)	<−37 (−35)	–	7 (45)	−9–15 (13–55)
Viscosity (Pa · s)				
At 38°C (100°F)	0.004–0.009	100.0	0.9	0.2–2.0
At 74°C (165°F)	—	0.9	—	—
At 100°C (212°F)	0.001–0.002	—	0.035	0.015–0.050
At 130°C (265°F)	—	0.035	—	—

Table 3
PARTICULATE AND NO_x EMISSIONS FROM SYNTHETIC AND PETROLEUM-DERIVED FUELS

Fuel Type	Fuel Nitrogen Content (wt%)	Unstaged Combustion: Particulate Loading (lb/10^6 Btu)	Unstaged Combustion: NO_x (ppm at 3% O_2)	Staged Combustion: Particulate Loading (lb/10^6 Btu)	Staged Combustion: NO_x (ppm at 3% O_2)
TSL	0.9	0.113	647	0.198	290
TSL*	0.9	0.086	378	—	—
No. 6	0.6	0.090	285	0.084	212
EDS	0.4	0.022	259	0.018	170
H-Coal	0.6	0.022	247	0.030	226
SRC-II	0.9	0.012	561	0.015	308

*Modified atomizer.

R&D Status Report
COAL COMBUSTION SYSTEMS DIVISION

Kurt Yeager, Director

SOLID BY-PRODUCTS AND HAZARDOUS WASTE DISPOSAL

This is the fifth status report on the activities of the solid by-products and hazardous waste disposal subprogram. Coal-fired power plants generate large quantities of solid wastes as by-products of combustion, coal cleaning, stack gas cleaning, and water treatment. With the implementation of the regulations pursuant to the Toxic Substances Control Act (TSCA) and the Resource Conservation and Recovery Act (RCRA), the requirements and regulations for handling, storing, disposing of, or utilizing these wastes are an important and costly portion of utility operations. Previous EPRI Journal *reports (June 1982, p. 46; May 1981, p. 36; May 1980, p. 43; and June 1979, p. 38) discussed the status of projects in the subprogram, which has the following objectives: to develop and demonstrate safe and economical methods for the disposal of sludge, ash, and sludge-ash mixtures; to provide a sound technical basis for the selection, preparation, operation, and monitoring of disposal sites; to develop methods for the identification, treatment, and disposal of hazardous residuals; and to demonstrate the technical and economical feasibility of the utilization of, or resource recovery from, power plant by products.*

Sludge and ash disposal manuals

One of the most popular series of reports in the subprogram has been the disposal manuals for coal ash and FGD sludge. These manuals present methods and costs of site selection and disposal; they are regularly updated to reflect current practices. The *Flue Gas Desulfurization (FGD) By-Product Disposal Manual* was first issued in 1979. The third edition, issued in January 1983 (CS-2801), contains significant revisions.

- Coverage of dry scrubber wastes as well as sludges
- Updated information on the chemical and physical properties of FGD by-products
- A description of current practices in the United States and other countries
- A review of the more recent federal regulations on solid-waste disposal
- Detailed information on site-selection methods, environmental monitoring, and site reclamation
- Updated computation methods for estimating by-product quantities and characteristics, leachate production rates, and new plant system costs

As part of the effort in preparing the disposal manual, a computer program, SLUDGECOST, was developed to generate cost estimates for sludge disposal systems by using procedures described in the manual. The SLUDGECOST code considers not only the type of disposal (ponding without fixation, landfill with stabilization, landfill with fixation, and landfill with forced oxidation) but also such factors as power plant size, remaining plant life, ash and sulfur content of the coal to be burned, distance to the disposal site, mode of sludge transport, land availability, and liner costs. The theoretical development of SLUDGECOST, description of the program, and results from the program are included in the computer code manual *SLUDGECOST: A Cost Prediction Model for FGD Sludge Disposal Systems* (CS-2556-CCM). The computer code manual and software are available from the Electric Power Software Center.

The sludge and the ash disposal manuals (CS-2801 and CS-2049) emphasize the construction of new facilities and have only limited usefulness for retrofitting existing waste disposal sites. A design manual to help utilities upgrade existing disposal facilities was published in August 1982 (CS-2557). This manual describes conditions under which upgrading may be applied, and it provides procedures and cost estimates for retrofitting. The manual also covers site closure procedures, the conversion of wet disposal systems to dry systems, liner design, installation of liners and leachate control systems, cost analysis techniques, and case studies.

In many cases, coal-fired power plants are located in congested areas where the availability of land for disposal of coal combustion by-products is limited. The land area requirements of coal power plant disposal sites can be reduced by compaction of the waste material and by reclamation of the area after the disposal site is filled.

A project is under way to evaluate several reclamation methods for disposal sites (RP1685-6). These techniques also increase the bearing strength and slope stability of the site. Construction practices for improving sites with soils that are too soft, loose, or wet are primarily based on the principle of preconsolidation. In the past, preconsolidation has been achieved through preloading, groundwater drainage, densification, or a combination of these methods. The purpose of this study is to investigate and summarize existing methods of site stabilization on soft and loose soils and man-made fills and to consider the applicability of these techniques to disposal site reclamation. The assessment will include recommendations for a field and laboratory testing program to evaluate the methods at a selected power plant disposal site. The project report is expected later this year.

Groundwater issues

A major goal of the solid-waste disposal regulations under RCRA is that of maintaining groundwater quality around disposal areas. Several important projects in this subprogram relate to groundwater protection, such as publication of a manual on monitoring methods, laboratory testing of candidate liner materials, field evaluations of groundwater protection methods, and the publication of simplified engineering groundwater models for site selection and monitoring support.

Groundwater monitoring and model development are the tasks of a nearly complete three-year project (RP1406). The monitoring study, recently completed, was conducted at the Columbus and Southern Ohio Electric Co.'s Conesville station to assess the performance of its disposal operation based on the fixation of FGD sludge by the addition of lime and fly ash. A report on the third year of the monitoring project (RP1406-2), prepared by Michael Baker, Jr., Inc., was published in July 1982 (CS-2498). A final report on the entire three-year monitoring program will be published later this summer. The results indicate that no leachate has been produced through permeation of the fixated-sludge material landfill at Conesville. The permeabilities of the fixated sludge collected at Conesville were found to be higher than the laboratory-scale tests, but through comparative testing the process of fixation was observed to significantly reduce the concentrations of some chemical species in leachates of the fixated FGD sludge. (The comparisons were made with untreated FGD sludges.)

Battelle, Pacific Northwest Laboratories has developed models and computer codes for both saturated and unsaturated groundwater flow (RP1406-1). The monitoring data base collected at Conesville was used to calibrate and verify VTT, the two-dimensional, finite-difference saturated groundwater flow model. In addition to the VTT code for saturated conditions, a code was developed for unsaturated flow conditions. The unsaturated flow code, UNSAT1D, uses a fully implicit finite-difference technique to simulate one-dimensional flow through a partially saturated flow system. The code is capable of simulating infiltration, vertical seepage, and plant uptake by roots. These are functions of the hydraulic properties of a soil, soil layering, root growth characteristics, evapotranspiration rates, and the frequency, rate, and amount of precipitation and/or irrigation. During 1982 the UNSAT1D code was demonstrated at the Antelope Valley station operated by the Basin Electric Power Cooperative near Beulah, North Dakota. Three demonstration cases were implemented with the code to simulate water movement through the waste material over a 15-year period. A report documenting the application of the code to the coal ash and dry FGD waste disposal site at the Antelope Valley station will be published soon. The VTT and UNSAT1D software programs are available through the Electric Power Software Center under licensing agreements.

The basic convective-dispersive transport equation, which has gained widespread acceptance, has inherent limitations for simulating contaminant transport. During 1981 research was initiated to develop a stochastic-convective approach to predicting contaminant transport. In late 1981 the equation formulation and data preparation required to apply this approach to transport analysis were completed. This report was issued in August 1982 (CS-2558).

A follow-up report presents the analysis of the Borden site in Canada, which should be useful in contaminant transport model evaluation. The data were used to select between two modeling approaches for dispersive transport. The dispersion was found to be skewed in the direction of the major fluid velocity. Neither of the two computer models evaluated was capable of handling the skewed dispersion. During 1983 a dispersive transport model capable of handling the skewed dispersion will be completed. This model will be documented and applied to determine its usefulness as an engineering tool for site selection, monitoring support, and assessment of remedial measures. Further modeling work will be carried on in the Environmental Assessment Department as part of its generic model development efforts.

Waste containment

When liners are chosen for waste containment and leachate control, liner compatibility with the waste material is an important design criterion. In a project described in detail in the May 1980 issue of the *Journal* (p. 44), 14 liner materials (6 soil admixed liners and 8 flexible membrane liners) are being evaluated to determine the effect of long-term exposure to nine types of utility wastes (RP1457). An interim report will be published shortly. This report concentrates on the screening methods used to select the candidate liners for the long-term testing, and on the short-term waste-liner compatibility tests performed on the selected liners.

By-product utilization

Utilization of or resource recovery from solid wastes is an important element of the industry's waste management strategy. In the past, this field has been characterized by site-specific demonstrations and applications, frequently successful, but having limited national impact. This subprogram is seeking to develop comprehensive research and demonstration projects, including a sufficient range of demonstration projects, adequate documentation, supporting laboratory research, and the development of specifications and manuals-of-practice to ensure widespread awareness and applicability of the results. The work is to be planned, coordinated, and sponsored by the appropriate user industries to facilitate acceptance of the results.

Although the technical suitability of fly ash products has been shown, other constraints or institutional barriers have occasionally kept these products from being utilized even where they appear to be economical alternatives to currently used construction materials. One of the principal objectives of the highway ash demonstration project is to overcome the constraints (RP2422).

Two research areas to support the use of coal ash in cement and concrete and for highway applications were described in more detail in the December 1982 issue of the *Journal* (pp. 14–19).

The fly ash metal recovery project at Oak Ridge National Laboratory (RP1404-2) was described in the June 1982 issue of the *Journal* (p. 47). Additional development work on the HCl direct acid leaching process is currently under way. Kaiser Engineers, Inc., is conducting a preliminary evaluation, including capital and manufacturing cost projections, of a commercial-scale facility for treating fly ash to remove alumina and other valuable materials by using the direct acid leach process (RP1404-4). Two large drums of fly ash will be processed by the multistage method in order to test and size equipment. Oak Ridge National Laboratory is providing the analytic work (RP1404-5). The report to be published in late 1983 will also provide recommendations for commercialization of the process.

To complement the disposal manual series, a by-product utilization manual was prepared by Michael Baker, Jr., Inc. (RP1850-1). The manual contains a methodology that utility personnel can use in assessing the market potential of their company's coal combustion by-products. By-product marketing is documented and assessed both regionally and nationally. The recently released report summarizes present utilization practices and anticipated future markets (CS-3122).

PCB research

Another element of the subprogram addresses the problems associated with specifically designated toxic or hazardous residuals. The emphasis to date has been on polychlorinated biphenyls (PCBs). The PCB work is coordinated with activities in the Electrical Systems and the Energy Analysis and Environment Divisions through the Interdivisional PCB Working Group. Responsibility within Coal Combustion Systems Division for PCB research encompasses disposal, spill clean-up, and portable instrumentation suitable for PCB measurements in the field. Beyond projects focused on specific new technology, this subprogram has produced a manual on disposal of PCBs and PCB-contaminated materials (FP-1207, Vol. 1, October 1979). Much has happened since that document was published, and an updated version will be produced this year, with publication by early 1984 (RP1263-14).

A new issue being reviewed is the relationship of polychlorinated dibenzofurans, polychlorinated dibenzodioxins, and other by-product organics to utility PCBs. A literature review is being prepared that will address the chemistry of formation of the by-products, analytic chemistry, toxicology, and incidents where by-products have been detected (RP1263-11). A significant conclusion is that although dioxins cannot be readily formed from PCBs, chlorinated benzenes are precursors.

There are two ongoing projects pursuing different avenues of PCB capacitor destruction. A chemical process is being developed by Acurex Waste Technologies, Inc., based on a dechlorination process that uses an organosodium reagent (Phase 1 final report, CS-2477). The current phase will produce design drawings, specifications, and more-precise cost data.

The second approach, also in the design phase, will use arc furnace technology for the total destruction of PCB capacitors (RP1263-12). It is planned that both systems will be mobile and will go to the utility capacitor storage facility rather than requiring transportation of the PCB equipment to the disposal facility.

Portable field instrumentation for PCBs is needed by utilities to provide timely information on the PCB concentrations at a spill site. To determine the effectiveness of spill cleanup requires an inexpensive, rapid, portable analytic technique. A portable gas chromatograph has been developed by S-Cubed to meet those criteria (RP1263-9). The instrument has been proved with liquid samples (i.e., contaminated mineral oil), and a protocol for soil samples is being developed. The instrument shown in Figure 1 uses nitrogen carrier gas through a packed column with a scandium tritide electron capture detector. A microprocessor is incorporated into the instrument and calculates peak area ratios, as well as identifying which of the four Aroclors commonly used by utilities is the major constituent.

Results of an Oak Ridge National Laboratory study to demonstrate the utility of an off-the-shelf portable infrared instrument for PCB analysis when using a horizontal multiple internal reflectance cell were reported in CS-2828. Follow-on work to refine the protocol is under way with C/S Associates of Oak Ridge, Tennessee (RP1263-10).

A third technique, being explored by Monsanto Research Corp., uses ultraviolet spectroscopy for PCB analysis (RP1263-13). The current project investigates the concentration-absorbance relationships for various Aroclors at a number of wavelengths. It also is developing a suitable technique for transferring PCBs from soil samples to an appropriate ultraviolet spectroscopy solvent.

In the area of spill cleanup techniques, laboratory work has been completed by Acurex on the feasibility of soil washing (RP1263-15). Results are promising, and the next phase will develop design information. The objective is to reduce cost and effort in cleaning up a large area of soil contamination and allow return of the washed soil to the original site rather than transporting the contaminated soil to a landfill for burial.

A project with Franklin Research Center has developed a poultice formulation for in situ removal of PCBs from spill areas (RP1263-8). More laboratory verification and parameter optimization is required before it will be ready to be tested in the field.

A project with Leland D. Attaway & Associates is exploring the literature and reviewing biotechnologies for application to PCB problems to ascertain which techniques are currently applicable and which will require further development (RP1263-16).

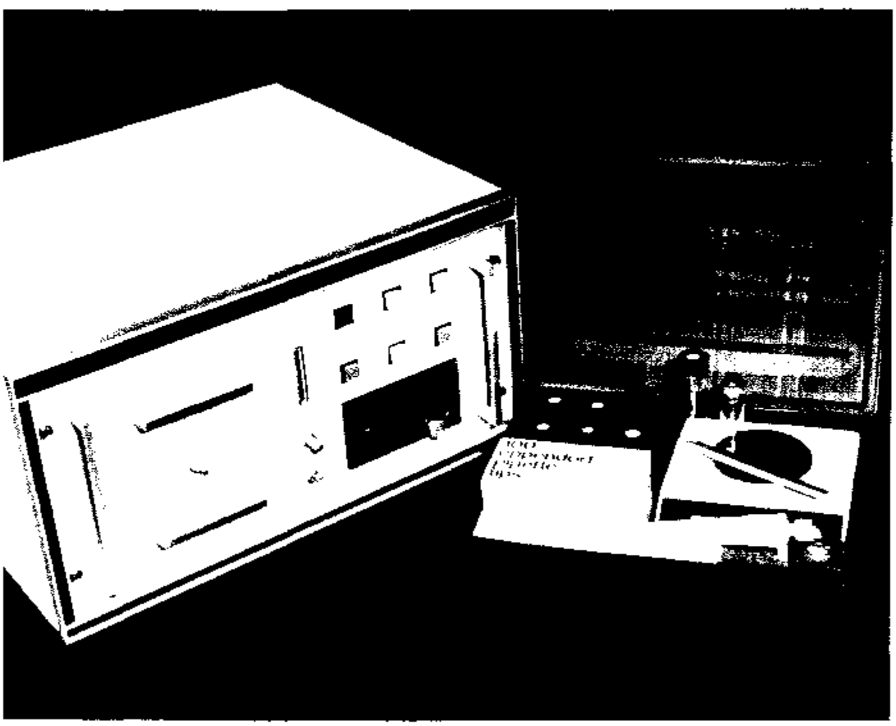


Figure 1 The PCBA-101 portable gas chromatograph for Aroclor analysis, developed under RP1263-9, will be commercially available this summer through the contractor, S-Cubed (La Jolla, California). A utility loan and testing program is being developed for the EPRI instrument.

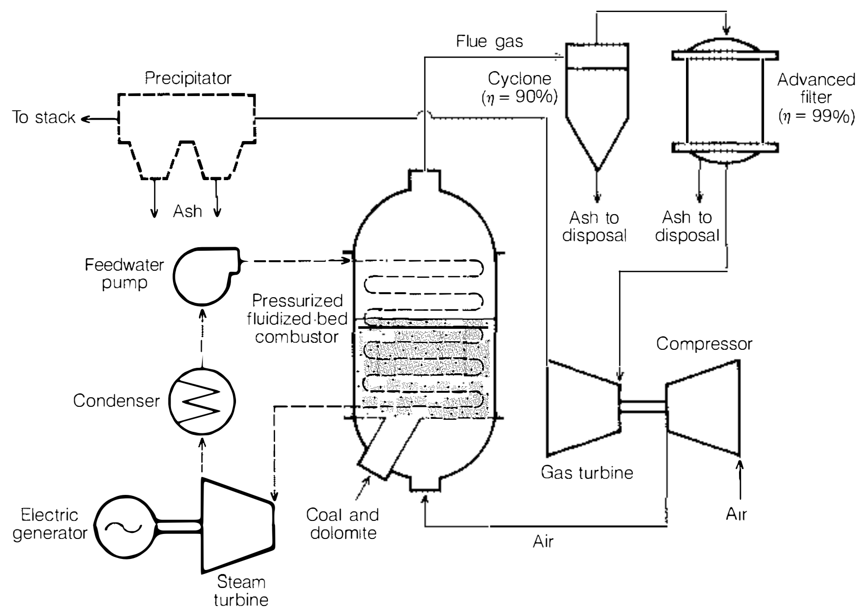
Disposal cost estimates

In 1982 a report prepared by Michael Baker, Jr., evaluated disposal alternatives under different regulatory assumptions (CS-2627). The evaluation was based on case studies at representative sites. The hazardous waste regulations used in the study were changed considerably in the regulations promulgated July 26, 1982, so the study has been updated to reflect these recent revisions. One of the conclusions of the revised study, now being prepared for publication, is that the cost of compliance with hazardous regulations—if hypothetically applied to utility wastes—would decrease by $920 million per year over the level of the previously proposed standards. However, these costs would still exceed the cost of disposal as a nonhazardous waste by $1.6 billion per year. *Subprogram Manager: Dean Golden*

PRESSURIZED FLUIDIZED-BED COMBUSTION

Before the utility industry can adopt pressurized fluidized-bed combustion (PFBC) of coal, gas turbines must be made reliable and EPA flue gas emission standards met. Either the installation of an advanced filter before the gas turbine or the addition of a baghouse or precipitator before the stack should permit PFBC technology to meet EPA particulate emission standards. The advanced filter would also reduce the particulate loading to the gas turbine and enhance its reliability. EPRI is sponsoring the experimental development of such advanced gas filters as ceramic fabric fibers, porous sintered ceramics, and electrostatic precipitators. This report examines the issues of particulate cleaning before the turbine and stack, as well as recent experimental filter performance.

Figure 2 Turbocharged boiler with cyclone and advanced filter for gas cleaning.



PFBC–combined-cycle gas turbines must operate under a range of temperatures and pressures, depending on the thermodynamic cycle used. The particulate concentrations in the gases range from 7000 to 20,000 parts per million (ppm). At the very least, turbine reliability requires two or three cyclones upstream to reduce particulate concentration at the turbine. Although cyclones can ensure satisfactory turbine life, such a cyclone train does not reduce particulates sufficiently to meet EPA standards and requires a baghouse or electrostatic precipitator before the stack.

Various advanced filters sponsored by EPRI and by DOE are being developed that can collect particulates with more than 99% efficiency. The combination of a cyclone and an efficient filter will reduce particulate load at the turbine, reduce turbine degradation by erosion or corrosion, and eliminate the need for baghouses or precipitators before the stack.

The turbocharged boiler is the PFBC thermodynamic cycle being advocated for its simplicity (Figure 2). In this system, particulate mass ranges from 7000 to 20,000 ppm. Three cyclones in series cause a pressure loss of some 10–12% of total compressor output. If the three cyclones collect particulates with 98% efficiency, the concentration entering the gas turbine is 200 ppm (Table 1). This particulate loading is higher than that recommended by gas turbine manufacturers. After expansion through the gas turbine, the gas must be further cleaned by an electrostatic precipitator to meet a stack emission goal of 10 ppm.

If one of the new advanced filters with a collection efficiency of >99% replaces the second and third cyclones, the pressure drop across the filters is reduced to 1–2% and the particle concentration entering and leaving the gas turbine is reduced to 10 ppm. Not only does this cyclone-filter combination meet EPA standards, but it also enhances turbine reliability and longevity.

Table 1
PFBC TURBOCHARGED BOILER WITH CYCLONE TRAIN AND CYCLONE–ADVANCED FILTER FOR GAS CLEANING

	Cyclone Train Filter System	Cyclone–Advanced Filter System
Pressure drop (%)	10–12	1–2
Particulate load (ppm)		
From combustor	10,000	10,000
To turbine	200	10
To stack	10*	10

*Particulate load at stack requires electrostatic precipitator or baghouse to meet EPA standards.

The size of advanced filters required to meet >99% collection efficiency depends on the type of filter chosen, the particulate loading, the gas volume flow rate, and the tolerable pressure drop. Ceramic fibers woven into cloth are a promising fabric filter for gases up to 900°C (1650°F). A cloth woven from an alumina-boria-silica ceramic (manufactured by Minnesota Mining & Manufacturing Co.) has already undergone testing at temperatures of 430–850°C (800–1560°F) and pressures of 0.1–1 MPa (1–10 atm).

Particulate collection efficiencies for both single and multiple filter elements have been measured in the 99.2–99.9% range. Zirconia fiber cloth (also manufactured by 3M), which promises increased flexibility, is now being tested for durability and performance at Westinghouse Electric Corp. and Acurex Corp. Based on this ceramic fabric filter technology, a 33-MW filter module is now being designed for possible operation at 450–850°C (840–1560°F) and 1.5 MPa (15 atm). Module costs and the economics of incorporating it into a turbocharged boiler plant are being determined.

In another type of filter the individual elements are solid porous sintered ceramic cylinders. These filters (manufactured by Schumacher'sche Fabrik) are being evaluated at Westinghouse, and preliminary tests have shown excellent collection efficiencies of >99.9%. However, results also show that these filter elements create a larger pressure drop and are more difficult to clean and package. Granular bed filters constructed by Combustion Power Co., EFB, Inc., and Ducon, Inc., have demonstrated collection efficiencies of ~99%.

Preliminary tests by Denver Research Institute on a tubular electrostatic precipitator have demonstrated that very high electric fields are possible, resulting in collection efficiencies of >99%.

Figure 3 shows the collection performance of several filter types. In some cases the test results are preliminary because they are based on laboratory-scale apparatus. Such results have been obtained over periods of 15–1000 hours. In all cases more development work is needed. Projected performance ranges are based on engineering extrapolations of available test results.

The physical size of a filter depends mainly on the volume of gas flow. In the case of the electrostatic precipitator, the collection efficiency can be readily selected over a wide range, depending on the collection surface area chosen.

Table 2 shows the relation between pressure and temperature and the filter size (volume and surface area) required for a nominal 100-MW (e) gas-steam combined-cycle PFBC power plant. The pressure drop is estimated. Although the data in the table are those for a fabric filter, they illustrate the approach for a design incorporating the three barrier filters in Figure 3. As the table shows, both filter surface area and volume are smaller if the filter precedes the gas turbine (at 450°C, 840°F; or at 900°C, 1650°F) than if the filter precedes the power plant stack (at 150°C, 300°F). Containment vessel design requires mechanical strength and thermal insulation for both extremes of the temperature range. At 1 MPa (10 atm), the pressure vessel must meet appropriate design codes and be lined with a cast refractory coating. The casing for a baghouse or precipitator of the size needed to filter flue gas at 150°C and 0.1 MPa (1 atm) is so large that considerable structural support is necessary for wind and snow loading.

The advantages of an advanced gas filter to operate at 450–900°C and 1 MPa (10 atm) are numerous.

- Particulate loading is reduced to <10 ppm at the turbine.
- EPA stack emission standards are met.
- Pressure drop is reduced and overall system thermal efficiency is improved.
- The need for a large precipitator before the stack is eliminated.

Project Managers: Owen Tassicker and Steven Drenker

Figure 3 The collection efficiency of various filters for use at 400–900°C.

Table 2
100-MW (e) GAS-STEAM COMBINED-CYCLE PFBC FABRIC FILTER PARAMETERS

	Temperature (°C); Pressure (MPa)		
	150; 0.1	450; 1	900; 1
Gas volume flow (m^3/s)	156	27	43
Cloth area (m^2)			
V_s = 1 m/min	9360	—	—
V_s = 3 m/min	—	540	860
Module volume (m^3)	2400	78	124
Pressure drop			
inches of H_2O	8	15	15
kPa	2	4	4

R&D Status Report
ELECTRICAL SYSTEMS DIVISION

John J. Dougherty, Director

UNDERGROUND TRANSMISSION

Fault location

The rapid location of faults in underground transmission systems is critically important to utilities in minimizing costs and in maintaining adequate system reliability. Because techniques now available are frequently time-consuming, EPRI instituted a project with Hughes Research Laboratories to develop a system for rapid, accurate, and unambiguous fault location (RP7874).

The equipment developed is particularly suited to locating high-resistance faults. As described in the September 1980 issue of the *EPRI Journal,* the system uses time measurements on traveling waves to establish the distance to the fault as a fraction of system length. The most important feature of this system is that only the forward traveling wave is used. Hence the system is relatively immune to errors from reflections that occur at impedance discontinuities at joints, terminals, and cable taps.

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*

High-pressure tests on PPP insulation

The most promising insulation material being developed for underground transmission is a laminate of cellulose paper–polypropylene film–cellulose paper (PPP). When combined with compatible dielectric fluids, the three-part laminate (Figure 1) provides the best of the electrical and mechanical characteristics of paper and the higher dielectric strength and appreciably lower dielectric losses of the polypropylene film. Because the dielectric losses are as much as one-third of those of low-loss paper, studies show attractive savings in costs of losses at all transmission voltages.

Development and application of the material to 138–550-kV high-pressure oil-filled (HPOF) pipe-type cables have been conducted by Phelps Dodge Cable & Wire Co. (RP7880-1). To acquire complementary design and supporting data, projects were issued to Pirelli Cable Corp. (RP7876-18) and to Sumitomo Electric Industries USA (RP7876-20) to conduct electrical strength tests for ac and impulse criteria on this promising material. Most of the previous testing on PPP in other countries was conducted at dielectric fluid pressures of 0.1–0.2 MPa. However, HPOF pipe-type cable systems operate at more than 10 times these pressures (1.5–2.0 MPa; 220–294 psi). It was considered important to establish the additional benefits of the high fluid operating pressures for PPP and provide a firm basis for increased reliability in reduced-wall PPP-insulated cable designs.

To reduce the cost and time expended and to obtain more correlation from repetitive tests, the electrical tests were conducted on assemblies of three or more insulating sheets compressed between specially prepared and stress-relieved electrodes. These were contained in a vessel or cell where samples could be exactly conditioned by application of heat (up to 135°C), and vacuum (to 10 μm or less). After drying, the PPP samples were impregnated with dried and degasified dielectric fluid and subjected to breakdown voltages at various operating pressures and temperatures.

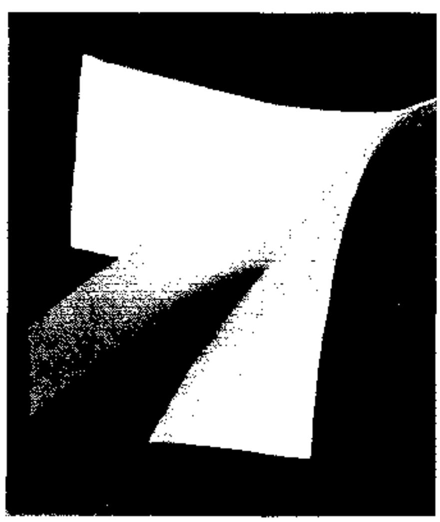


Figure 1 A new three-part laminate of paper, polypropylene, and paper exhibits exceptional dielectric strength when combined with certain dielectric fluids for underground cable insulation.

In general the test results confirmed the following.

- An increase in ac dielectric strength of 40–45% with an increase in applied fluid pressure from 0.1 to 2.0 MPa (14.7–294 psi)
- An increase in impulse dielectric strength of 10–15% with the same increase in dielectric fluid pressure
- An ac dielectric strength for PPP generally 25% or more higher than that for paper
- An impulse dielectric strength of about 25–30% higher than that for paper

These results (from more than 200 tests) confirm the superior dielectric properties of PPP and suggest that high-pressure PPP-insulated cables could be designed for an ac stress some 70% higher than that for paper.

EPRI's program for PPP-insulated HPOF pipe-type cables indicates substantial costs and technical benefits for 138-550-kV underground transmission. Plans include testing a 345-kV cable at Waltz Mill in the near future. *Project Manager: Stephen Kozak*

OVERHEAD TRANSMISSION

Transmission line maintenance—a new tool

Utilities have a long history of safe and efficient operation of their transmission lines. Personnel responsible for keeping lines in service and for quick restoration when failures do occur have used the latest technology to keep ahead of the ever-increasing demands of utility systems. Recently, changes in typical operating requirements have increased the challenge, primarily because of the following.

□ The high cost of capital has reduced line construction, and existing lines have become more heavily loaded; thus, lines must be maintained while energized more frequently.

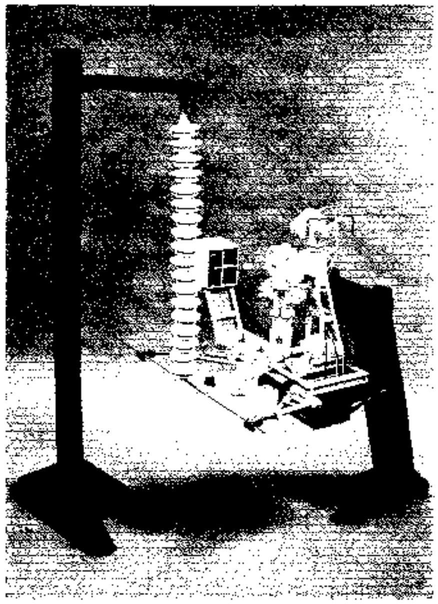
□ The loss of a major circuit will usually mean higher energy costs; circuits must therefore be restored as quickly as possible, even if bad weather prevents conventional line work.

An outstanding example of a utility's successful application of technology is the aerial lift vehicle, which originated with the orchard industry and has now revolutionized electric line work. In spite of its high initial cost, the bucket truck has proved cost-effective and virtually indispensable. Helicopter construction, another seemingly expensive option, has been used to reduce line cost in many instances. One could cite many other examples of the industry's leadership in applying new or different technology to extend the lineman's capabilities, while reducing cost.

Now the power industry needs new ideas to improve the ability to work on energized lines, particularly in adverse weather conditions. A new technology that has permitted important cost savings for other industries is robotics. Could robotic technology reduce transmission line maintenance costs? What are the technical problems in applying robotics to utility needs? Could such a device work in adverse weather? To answer these questions, EPRI funded a project with Southwest Research Institute (SwRI) to develop a conceptual design for energized-line maintenance with robotics and then determine if the concept is economically and/or technically feasible (RP1497-1). This work is now completed and the final report is available. In summary, the study showed that manipulators now available (the type used for underwater work by the oil exploration industry) will do the job. Because the initial cost of a manipulator is high, a surprising result of the economic study indicates that this device would reduce costs for most utilities that have major transmission systems.

The project team was composed of engineers from SwRI who had experience with undersea manipulators, operating personnel from Philadelphia Electric Co., and live-line maintenance experts from A. B. Chance Co. The concept was to mount the manipulator atop an insulated boom truck (Figure 2), where it would work in place of a lineman. From a weather-protected console on the ground, the lineman would control the manipulator, using closed-circuit TV. This device has been named Tomcat (teleoperator for operations, maintenance, and construction, using advanced technology).

Figure 2 A scale model of the remote-control maintenance device was built to test its ability to work on energized lines; the manipulator showed that it had the dexterity to affix the stabilizing arms to the conductor, remove tools from the side-mounted holder, and perform typical maintenance/repair jobs. In practice, the device will be mounted on a utility transmission insulated boom truck in place of the bucket.



Initially, the study was labeled a man-on-the-moon project, and the research team proceeded very cautiously because there was considerable doubt that such a concept was feasible and grave doubt about its cost-effectiveness. Working closely with experts from utilities, the team embarked on a methodical investigation to determine if this idea did have merit. The results: For most utilities, use of Tomcat will be cost-effective; it is technically feasible to build a full-size Tomcat, using slightly modified components now available.

In a follow-on effort, a full-scale prototype will be built and tested for both its mechanical and its electric characteristics. If Tomcat passes these tests satisfactorily, it will be loaned to a utility to perform everyday maintenance work. Tomcat's performance in the field will determine if this new tool can really be effective in restoring lines more quickly, especially in adverse weather, and if it can reduce overall maintenance and/or repair costs. The project's advisers have prepared a list of innovative tasks for Tomcat and are eager to put it to work. *Project Manager: John Dunlap*

Transmission tower foundation design

The primary objective of a recently completed project (*EPRI Journal,* March 1981, p. 46) was to evaluate the state of the art in the design of uplift/compression transmission line structure foundations and to recommend more cost-effective and accurate approaches to the industry (RP1493-1). Evaluation of tower response to differential foundation movement was also investigated to provide engineers with a better insight into how this movement affects the load-carrying capacity of typical transmission line towers.

To determine the extent that various foundation types are used across the industry, EPRI sent out over 200 questionnaires to electric utilities. Every utility known to have overhead transmission lines as part of its system was included in the survey. Responses were received from 130 electric utilities, with over 30 of these offering to furnish results of foundation tests performed on their systems.

This project resulted in a detailed evaluation of transmission line structure foundation design procedures and soil exploration techniques. A unified model for analyzing and evaluating foundation designs has been developed that is based on actual failure modes of the foundation and surrounding soils rather than on empirically derived relationships. Recommendations are made for economically obtaining accurate and reliable soil data, as these represent the single most influential variable.

Emphasis was placed on minimizing the uncertainty associated with currently available design models and on assessing the variables associated with soil-testing methods; the results of this effort are directly applicable to the reliability-based design procedures being developed for transmission lines in another EPRI research project (RP1352). On the basis of these results, a meaningful research project is planned that will involve a full-scale foundation and soil test program to verify this unified model in a wide range of soil types across the country (RP1493-2). Cornell University is the contractor.

Research results are available for a related project now completed on laterally loaded, drilled pier foundations (RP1280, EL-2197). The objectives of this project were to develop an improved analytic model for predicting the behavior of drilled piers subjected to high overturning moments, and to verify this model by performing full-scale, destructive field tests on drilled piers, fully instrumented and installed in a wide variety of subsurface soil conditions.

As shown in a previous article (*EPRI Journal*, March 1980, p. 43), the response of laterally loaded drilled piers is highly nonlinear. Because foundation designs are controlled by allowable displacement, a more accurate method of predicting ground-line displacement was needed. A series of 14 full-scale field tests showed that existing models, in general, overstated ground-line displacement and understated ultimate capacity, both of which tended to exaggerate the size of foundation that was needed.

EPRI has since developed and verified a nonlinear model that accurately predicts displacement of laterally loaded drilled piers at all load levels in a wide variety of soil types. Fourteen utilities participated in a full-scale testing program that measured not only foundation movement at the ground line but also rotation of the foundation, internal loads in the foundation, and loads transferred to the soil at various levels.

The results of this project are available through the Electric Power Software Center as a computer program called PADLL (pier analysis and design for lateral loads), which can be obtained in both CDC and IBM formats. PADLL has been used successfully by many utilities to reduce foundation sizes, and thus costs, by a significant amount. *Project Manager: Phillip Landers*

New ground-line repair system (pole stubbing)

EPRI has developed a method for repairing wood poles that have deteriorated at or below the ground line, and it is applicable to both transmission- and distribution-size poles (RP1605). The method employs a section of tubing with a helical corrugation (similar to a culvert) that is "screwed" into the ground by vibratory action and a conventional torque head that is standard on most utility augering equipment. Tests show that these tubular sections can be screwed around the butt of a pole in less than one minute, thus reducing the total time required to economically repair a pole to less than one hour (Figure 3).

Once the tubular section is in place around the butt of the pole, the annulus between the pole and the tube is filled with specially formulated resin that has a cured strength several times that of standard concrete. However, unlike concrete, which requires a long curing time, the resin reaches adequate strength to release the pole by the time the job is done and full strength in less than 48 hours. In addition to its superior strength, this resin has another feature—it contains a time-release fumigant that will kill the microorganisms that cause wood pole decay, thus preventing further deterioration of the pole under the sleeve.

Cost-effective breakaway pole options may also be possible, but more work is required to develop this option. When setting new poles in undisturbed soil, a newly developed impulse grout injection system may be needed to "pre-rip" the soil prior to screwing the tubular section into the ground. The impulse grout injection system accelerates a small volume of fluid (typically, less than one cup) to velocities several times the speed of sound. When fired into hard-packed clays and shales, the fluid penetrates the soil in a discrete pattern up to 4 ft (1.2 m) deep, thus also making it easy to install the tubular section for setting a new pole. Tests show that by varying the configuration of the nozzle, any desired penetration pattern can be obtained.

Fluids that can be injected with this system include water, many of the higher viscosity resins, and other chemicals that may be required to improve the soil's load-bearing properties.

Research is under way to expand the application of this equipment. Other areas that are being explored include the following.

- Shooting an electrolytic chemical into the ground to improve the grounding capability of the soil
- Injecting resins, similar to those being used for the pole-stubbing application, directly into the soil to give it a surface load-bearing strength at least equal to concrete, without disturbing the soil
- Increasing the strength of existing foundations and direct-embedded poles
- Installing anchor rods quickly and economically by the impulse grout injection system, which is already able to advance a 2.5-in-diam rod through typical soils at the rate of 10 ft/min
- Installing cathodic protection systems, both impressed-current and galvanic, by the impulse grout injection system
- Stabilizing caving excavations
- Sealing wastewater ponds by installing a curtain wall of resin to prevent the seepage of contaminant into the environment

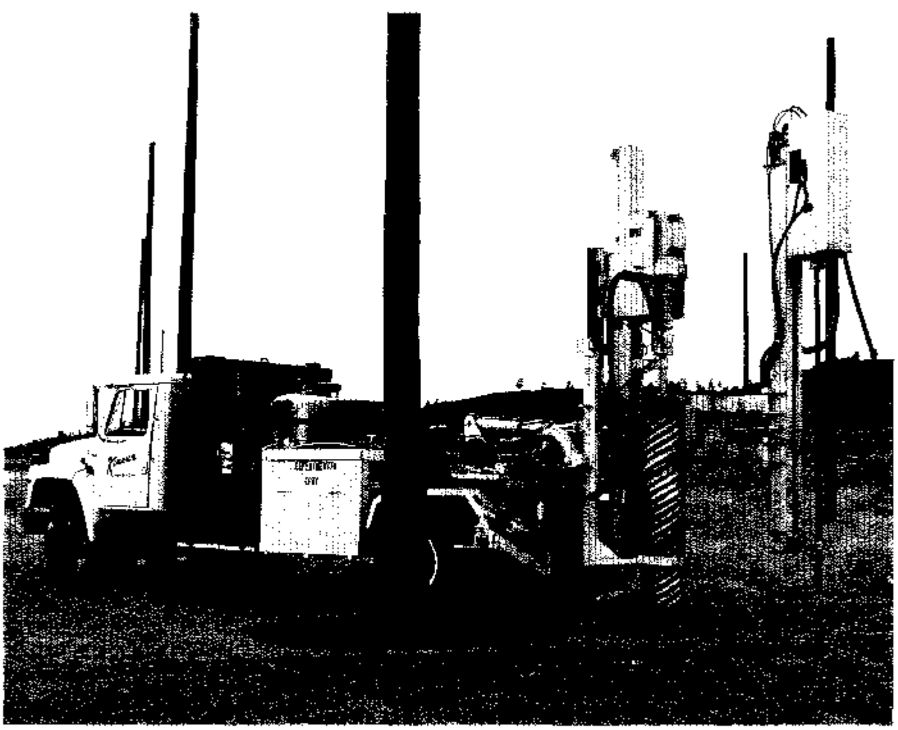


Figure 3 With a new ground-line pole-repairing (stubbing) technique, standard industrial augering equipment with vibratory torque-multiplying action can be used to screw a section of helical tubing (culvert) into the ground around a pole butt in less than one minute. The pole at left has already been repaired, and the annulus between the pole and the steel tube was filled with a resin that cures to a strength several times that of concrete; the resin also contains a time-release fumigant to prevent further decay under the repair section.

Work is under way to develop many of these applications, with results anticipated later in 1983.

A little more work is still required to fine-tune the equipment for pole stubbing and even more work for its use in constructing transmission line structure foundations. Utility assistance will be required to evaluate this equipment in actual construction and maintenance activities. A utility-cosponsored field testing project is planned to begin in the summer of 1983, at which time cosponsoring utilities will be loaned this pole repair and anchor installation equipment on a trial basis. As part of the project, utilities will contract directly with EPRI's contractor, Kinnan and Associates, Inc., of Camas Valley, Oregon, for one month during the loan period. This will provide participating utilities the important hands-on experience that can lead to significant savings through the extension of the life of ground-line-deteriorated poles. Further, it is hoped that by using this advanced pole-stubbing equipment in conjunction with the newly emerging nondestructive testing instrument for wood poles, which is capable of determining the strength of in-service wood poles to within 500 psi (3.45 MPa) fiber stress (RP1352), cost-effective wood pole maintenance programs can be developed for both transmission and distribution applications. *Project Manager: Phillip Landers*

POWER SYSTEM PLANNING AND OPERATIONS

Software guidelines

The Power System Planning and Operations Program has produced a set of software development and maintenance guidelines (RP1714). Developed as an EPRI-wide responsibility, these guidelines, which became available from the Research Reports Center in May 1983, have two intended applications: use in EPRI code development projects and use by electric utilities to procure or produce software for their own use.

Up to 11 documents may be produced from a major software project by using these guidelines. The documents may be divided into two general classes: design/development and user/maintenance.

The documents associated with design/development include the requirements specification document (describes the precise requirements for the software being produced), the preliminary design specification (describes the design down to the subroutine/function module level), the detailed design specification (provides the logical design within modules), and the test plan (describes the plan for testing the completed code).

The documents associated with the user/maintenance functions include the installation instruction manual (describes the procedures to install the completed program on a particular computer), the user manual (provides the necessary information to use the program), the test analysis report (documents the results of the testing by the code developer), the technical theory manual (describes the engineering and mathematical computations related to the software), the final report (describes the research results and experiences), the program reference manual (describes program structure for maintenance purposes), and the program log (provides a history of the designs, decisions, modifications, and so on).

The documents are described more fully in the twelve chapters in the guidelines. The individual chapters may be divided into two classes: general topics and specific code development steps. The first five chapters, which describe the general topics, are (1) Overview, Usage, and Amendments; (2) Software Development Life Cycle and Phases; (3) Software Cost Estimation and Schedule Guidelines; (4) Software Management, Evaluation, and Control Guidelines; and (5) Documentation Guidelines.

The remaining chapters (6 through 12), which describe the specific steps in code development, are (6) Requirement Specification Guidelines, (7) Design Guidelines, (8) Coding Guidelines, (9) User Application Documentation Guidelines, (10) Testing and Validation Guidelines, (11) Updating and Maintenance Guidelines, and (12) Delivery and Evaluation Guidelines. Each chapter has been developed so it may be used independently of the other chapters.

These guidelines are being used in several EPRI software development projects. Following the guidelines will produce a higher-quality software that is more easily used. Science Applications, Inc., is the contractor. *Project Manager: John Lamont*

TRANSMISSION SUBSTATIONS

Bushings for gas-insulated equipment

The design and manufacture of air entrance bushings for SF_6 circuit breakers or compact gas-insulated substations (GIS) is a real challenge. Bulk gas-insulated bushing designs are quite expensive at high voltages, such as 500 kV. Also, there is a concern that any porcelain failure of large bushings could be catastrophic, hurling porcelain pieces outward at great force; this would pose a danger to adjacent equipment and to people in the immediate vicinity.

Two research projects addressing this problem were initiated, one with Lapp Insulator Co. (RP1423-1) and the other with Brown Boveri Corp. (RP1423-2). Both projects aimed at developing new technology suitable for producing capacitive-graded, oilless bushings that are explosion-resistant, smaller than bulk gas-insulated bushings, and above all, lower in cost.

The project with Lapp focused on extending the manufacturing techniques used to produce paper–epoxy-resin, capacitive-graded bushings for 500-kV applications.

Commercially available crepe paper with the high crepe specifications can only be bought in widths up to 90 in, which sets the limit on the length of the bushing core. Wider paper available from another supplier does not have the deep crinkle necessary to provide the give for the epoxy shrinkage as it cures. Therefore the primary challenge was to develop suitable casting methods for using this low-crepe paper. A secondary objective was to eliminate the oil normally used in the space between the paper-resin core and the porcelain shell and replace it with a highly viscous polymeric compound having suitable dielectric properties.

The work on this project established a practical limit on the size of the bushing core that can be made when using commercially available paper. Although it is economical to make oilless bushings for applications up to 230 kV, the limitations of the available paper width make the manufacturing of the cores too expensive for bushing sizes larger than 230 kV.

The objective of developing suitable casting methods on bushing cores made with low-crepe paper could not be fulfilled. The large bushings made with low-crepe paper cracked during curing because of the large epoxy mass and uneven shrinkage caused by the exothermic reaction. Cracks or even small voids are not acceptable in the highly stressed region of the bushing cores.

The project succeeded in eliminating oil in the space between the core and the bushing shell through the use of a suitable polymeric material, which was successfully tested in a bushing for the application.

During the course of this project a new design concept was developed. This concept, labeled hybrid bushing, uses a paper core that is epoxy-impregnated only at the bottom end. The remainder of this paper, which extends into the air end of the bushing, is impregnated with oil much like conventional bushings used in oil-filled transformers. The epoxy core eliminates any possibility of oil leaking into gas-insulated equipment. Casting only the bottom end of the core in epoxy makes the manufacturing more controllable and manageable. Even after the EPRI project was completed, Lapp continued to pursue the hybrid bushing design and has carried this work to a successful test on a 230-kV prototype bushing.

The second project, with Brown Boveri, was directed toward developing a new SF_6 foam material suitable for this bushing application. The processing and the materials necessary to produce a highly insulating foam were successfully completed. The foam was made from polyurethane resin mixed with SF_6 gas. The resin, in a liquid state, is mixed with high-pressure (300 psi, 2.17 MPa) SF_6 gas in a high-shear mixer. When dispensed into a low-pressure (45 psi, 414 kPa) mold, this mixture foams into a material with excellent dielectric strength. Small samples of the material exhibited electrical strength in excess of 700 V/mil. This turns out to be better than the parent resin material itself.

Small prototype bushings were cast with this foam insulating material with excellent test results. The dielectric losses within the material, however, are too large at high voltages for this design concept to be extended to 362-kV applications. The extremely high thermal insulating qualities of this material impede the dissipation of heat generated by dielectric losses within the material under an energized state.

Even though this is an excellent insulating material that possibly has many applications, the objective of applying this material to high-voltage bushings was not realized. Low-level work to improve the thermal conductivity of the material will continue so that its application for bushings can be reconsidered. *Project Manager: Vasu Tahiliani*

Advanced thyristor valve for HVDC

Earlier reports described the development of higher-voltage light-triggered thyristors (RP669-2), two-phase Freon cooling of thyristors (RP1207), a cesium-arc infrared light source (RP1291-2), and the integration of these features into a prototype building block for an advanced HVDC valve (RP1291-1). Contracts have now been signed with General Electric Co. for fabricating an advanced valve (RP1291-5) and installing it at the Sylmar HVDC station of the Los Angeles Department of Water & Power, the host utility (RP1291-4). Sylmar is the southern terminal of the Pacific Intertie; its northern terminal is Bonneville Power Administration's Celilo station, The Dalles, Oregon.

The Pacific Intertie, operating over a distance of 1350 km, has a nominal capacity of 1600 MW, 2000 A at ± 400 kV. It has been in operation since 1970. The converter at the Sylmar end consists of 6 three-phase bridges, each operating at 133 kV, 2000 A dc, three in each 400-kV pole. Initially, each of the bridges used six mercury arc converter valves. However, an electrically triggered thyristor valve has been under test in one bridge for several years. The light-triggered advanced thyristor valve will be tested in this three-phase bridge, which will then contain one light-triggered thyristor valve, one electrically triggered valve, and four mercury arc valves. Scaling up for commercial operation has highlighted a series of new problems to be solved.

□ Redundant light sources and pulser supplies are required to permit uninterrupted operation of the valve in case any one light source fails. Because these lamps are located in a low-potential area, they can be maintained without interrupting valve operation. Some difficulty was found in directing the light from two sources through fiber optics to properly illuminate the light-sensitive thyristor gates. Suitable optics have been designed to eliminate this problem.

□ Controller software, suitable for interfacing with existing converter controls, has been programmed. Included among the software needs are startup requirements and control of the two-phase cooling system. The program is now being debugged.

□ Status-monitoring equipment to permit continuous monitoring (at the operating position) of the health of each thyristor is being fabricated.

□ The pulser supply for the cesium arc has been designed with a keep-alive circuit to permit instant start.

□ A full-scale valve-cooling system, sized for the requirements of LADWP's Sylmar station, has been designed and is being assembled. The system will be tested by using resistors mounted on the heat sinks as surrogates for the thyristors.

□ An added external problem has arisen. As a result of high water runoff and low power demand in the Pacific Northwest, it is anticipated that the 1983 shutdown time of the Intertie will be minimal in order to make maximum use of available low-cost hydro power. This will make the time window for installation and checkout of the new valve quite precarious and could result in a major delay. Every effort is being made to accelerate fabrication and factory test to meet the new deadline, thereby avoiding this delay.

Project Manager: Gilbert Addis

DISTRIBUTION

Amorphous steel core distribution transformers

Annual losses in approximately 20 million distribution transformers now in service in the U.S. amount to 15×10^9 kWh. At $0.04/kWh this amounts to $0.6 billion in losses per year. Amorphous alloy steel has the potential of reducing core losses by 50–60% over the grain-oriented silicon steel that is currently used. Not since the 1930s, when grain-oriented steel became available, has a new core material appeared with such significant improvement in loss characteristics.

Certain other characteristics of the amorphous steel developed by Allied Corp. (RP1290-1) are distinctly different from those of grain-oriented silicon steel. The amorphous steel now available is only 1–1.5 mils thick, compared with silicon steel at 7–12 mils; it has poor ductility and is brittle when annealed. These factors present a challenge to the distribution transformer designer.

EPRI, with Empire State Electric Energy Research Corp. cofunding, recently initiated a project with General Electric to evaluate and develop innovative transformer designs and manufacturing processes to economically use this amorphous material (RP1592). In addition to the comprehensive design and manufacturing investigations, the project includes the installation of a pilot manufacturing facility and the production of a thousand 25-kVA transformers. Also, several marketing surveys and ongoing analyses will be used to monitor the evolving commercial potential of amorphous steel core distribution transformers. The eventual success in commercializing these transformers will depend greatly on the ultimate price of the amorphous metal, the ingenuity of the transformer manufacturer in their design, and the willingness of utilities to evaluate the total cost of ownership. Certainly, the significant increase in energy cost over the past five years provides substantial economic incentive for this new development.

Further on in the project, after the selection of design and the pilot manufacturing facility, utilities will be asked to install and evaluate the thousand transformers that will be made. It is anticipated this activity will take place in 1985. *Project Manager: Robert Tackaberry*

R&D Status Report
ENERGY ANALYSIS AND ENVIRONMENT DIVISION

René Malès, Director

IONIZING RADIATION

An enormous effort by the federal government and other funding agencies has provided an extensive data base on the health effects of ionizing radiation. Therefore, EPRI's Environmental Assessment Department decided not to focus its efforts on this area. Instead, because relatively little was known about the effects of exposure to fossil fuel combustion products, EPRI chose to emphasize that line of research. It was recognized, however, that some specific issues regarding ionizing radiation might arise that could require EPRI attention. Two such projects have been undertaken: a study of utility radiation-protection programs and a study of workers at nuclear power plants.

Radiation-protection training for utility reactor employees is required by NRC and is conducted at each site. Although safety training is widely practiced by utilities, there were particular reasons for EPRI's interest in radiation-protection training. One of these was the very sensitive matter of instructing employees about the biological and reproductive effects of exposure to ionizing radiation. Another was that each utility had independently developed its own training program and no interutility comparisons had been conducted. How successful were the programs? What kinds of training materials were being used? How much variability was there among plants?

The study undertaken in 1980 to examine these questions was small in scope. Five utilities were visited by the investigator, and some 30 employees were interviewed at two different facilities. Despite the small sample, this survey was sufficient to indicate that a good deal of variability does exist among utilities with regard to training procedures. The results are reported in EA-2420-SR.

The second study deals with a controversial issue growing out of radiation research and the estimation of effects at low (i.e., occupational) levels of exposure. Although a proportional (linear) extrapolation from higher exposures to estimate the effects of low-level exposures has been the convention, some experts continue to express doubts about the adequacy of this assumption. Most such experts believe the assumption overstates the likely level of effects from radiation at low exposure levels. Because the utility workforce has the largest aggregate exposure to ionizing radiation, it was proposed that a study of this population be undertaken to provide assurance that occupational exposures in the utility industry create no unusual hazard.

There is a second reason for studying utility nuclear employees. The assumption has been made that the only occupational hazard among this group of employees is ionizing radiation. It is possible, however, there are other exposures (physical or chemical) that may also influence the health of this workforce, or that may modify the response to ionizing radiation. In other words, confident conclusions about the safety of employment in the nuclear industry cannot be reached without a study of the health of the specific workforce concerned, and no such study has as yet been reported. The EPRI effort, then, is not limited to ionizing radiation but encompasses all health-related aspects of work in the nuclear industry.

A project has been initiated with Oak Ridge Associated Universities (RP2088-1) to examine the existing NRC exposure records. The researchers are also to determine whether records on cause of mortality can be assembled for this workforce. Finally, they are to evaluate whether a full-scale study based on those records can provide evidence for assessing the linear assumption.

If it appears feasible, a follow-on study will require three to four years. It would help resolve remaining uncertainties regarding the magnitude of low-level radiation effects. In particular, it would provide direct evidence, from a fairly large human population, on the appropriateness of the linear dose-response model of radiation health effects. *Project Manager: Walter Weyzen*

DECISION FRAMEWORK FOR AMBIENT AIR QUALITY STANDARDS

A decision framework for analyzing ambient air quality standards and their impact on public health and welfare has been developed and demonstrated under RP2141-2. Uncertainties about peak ambient levels, the size and location of the susceptible population, and the extent of significant health and welfare effects induced by various exposure levels influence the assessment of potential consequences of alternative standards. The decision framework integrates judgments regarding these key uncertainties with additional information on ambient concentrations, exposure, and health and welfare effects to provide a more explicit basis for decision making.

Decision-making approaches

Decisions on ambient air quality standards are of great importance to the electric utility industry and its customers because these decisions may imply changes in the allowable emissions of sulfur oxides, nitrogen oxides, particulates, and other substances from new and existing power plants. The Clean Air Act requires the EPA administrator to issue and periodically revise national standards for air pollutants that might endanger public health and welfare. The primary standard is to be set at a level to protect the public health, allowing an adequate margin of safety, and the secondary standard is to be set at a level to protect the public welfare from any known or anticipated adverse effects. In practice, the impact of low ambient concentrations of air pollutants on public health and welfare are uncertain, and much judgment must be exercised in determining appropriate standards.

How can ambient air quality standards be set so as to avoid potential adverse effects on public health and welfare and, at the same time, avoid unnecessary requirements for emissions control? An approach often followed in the past has been to set the maximum allowable ambient level well below the concentration at which any physiological changes can be detected in any subgroup of the population. Such a standard can be burdensome economically, however, while serving to avoid only innocuous or extremely rare health effects.

Another approach is to assess the incidence and severity of adverse health or welfare effects for alternative proposed regulatory standards. This type of assessment is inherently difficult because two complex processes must be specified: the variation of the ambient pollutant concentration at different times and locations, and the susceptibility of humans (or other receptors of concern for welfare assessment) to adverse effects from exposure to a given ambient concentration. The susceptibility of particular individuals to adverse health impacts may depend on preexisting conditions, such as asthma, and on personal habits and activities, such as smoking and the extent to which the individuals engage in vigorous exercise. Thus, assessing the impact of a proposed standard involves simultaneously determining variations in air quality and in human activity patterns, with emphasis on the population subgroups that are especially prone to health impairment from low-level exposure to the air pollutant.

The decision framework developed under RP2141-2 is intended to provide the basis for conducting this type of assessment. It is intended to serve as an analytic aid in local, state, and national regulatory decision processes and in the identification of important research needs relating to air quality regulation. The framework represents a powerful, flexible tool for summarizing the relationships among regulatory standards, ambient concentrations, population exposures, and adverse health or welfare impacts. These relationships may be complex and uncertain; typically the health or welfare consequences of an air quality standard are not known at the time an adoption decision must be made. The use of decision analysis methods permits the characterization of uncertainties associated with specific scientific and technical issues. Then, on the basis of these characterizations, it is possible to assess the overall uncertainty regarding the extent of health or welfare impacts under a proposed standard.

Framework structure

The assessment of effects for proposed alternative air quality standards is carried out in a series of stages, each of which is represented by a model. Together these models make up the decision framework (Figure 1).

An air quality standard will have effects on ambient concentrations to the extent that it imposes regulatory controls on emissions sources. By changing the extent and the time pattern of emissions, such controls change ambient pollutant concentrations. The controls will typically involve costs for achieving a reduction in emissions or a change in the pattern of emissions over time. The user of the framework must specify the relationships linking standards to ambient concentrations and control costs.

Although the relationship between alternative standards and ambient concentrations is conceptually part of the framework, an explicit model of this stage has not been included in the implementation. Instead, it has been assumed that descriptions of spatial and chronological ambient concentration patterns will be provided for each alternative standard. Such descriptions might be based on existing monitoring data, on projections of monitoring data under assumptions of a rollback in emissions from a major source (such as a power plant), or on the output of a complex airshed model that considers multiple sources.

The ambient concentration patterns may be specified either from frequency data or by using a standard functional form for the frequency distribution of concentration over time. Different patterns can be specified at different locations and for different time periods, such as weekdays versus weekends. For many important acute (as opposed to chronic) health effects, the main concern is with peak ambient levels, which may occur only a few times a year.

The exposure model identifies and describes the location of populations whose health may be at risk (or, more generally, receptors of concern for the assessment of health and welfare effects). Sensitive subgroups of the population may be of particular concern, and these subgroups may be especially susceptible to health impairment when

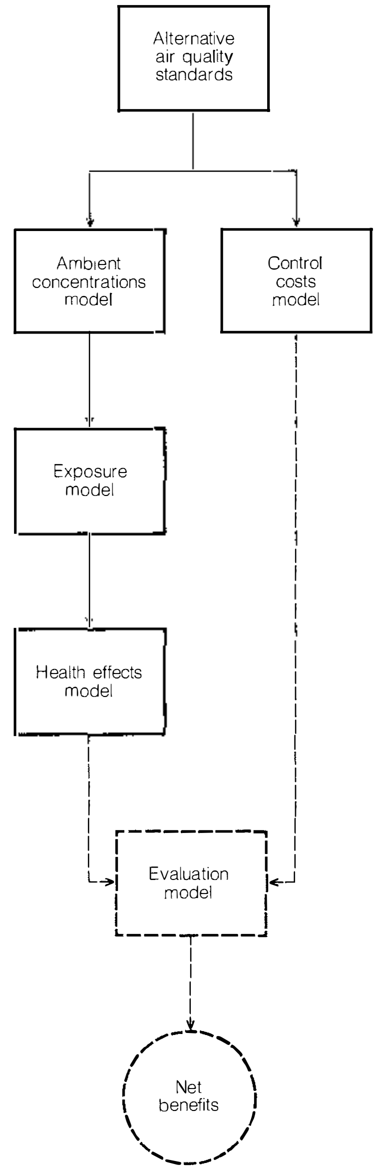


Figure 1 Decision framework for assessing air quality standards. For each alternative standard, ambient concentrations and control costs are determined. Next the exposure model identifies the susceptible population. Then, given ambient concentration patterns and the geographic distribution of the susceptible population, the health effects model determines the occurrence and severity of health and welfare effects. When appropriate, control costs can be compared with health effects to estimate net benefits; the evaluation model has not been included in the current framework, however, because regulations prohibit such comparisons.

they are engaged in specific activities. For example, for the short-term ambient SO_2 standard recently proposed by EPA, the sensitive population is asthmatics, who may suffer bronchoconstrictions if exposed to low levels of the pollutant while engaged in vigorous exercise. The exposure model must specify the number of persons susceptible to the health impact in different locations and at different times.

The occurrence and severity of health effects (or welfare effects) are described in the next stage of the framework. This involves a model that specifies the fraction of the susceptible population that will suffer effects of different levels of severity when the population is exposed to a specific ambient pollutant concentration. It may be appropriate to distinguish health effects that are physiologically observable from related or subsequent effects that are considered to be significant health impairments. For example, bronchoconstriction may lead to asthma attacks in some, but not all, asthmatics.

For cost-benefit analysis it may be useful to compare the health or welfare effects of standards with control costs, as shown in the last stage in Figure 1. For primary ambient air quality standards, however, cost-benefit analysis may not be appropriate as a basis for regulatory decisions. The Clean Air Act specifies that these standards shall be set to protect public health, allowing an adequate margin of safety. Thus they must be based on an assessment of the potential extent and severity of health effects.

The scientific information describing ambient pollutant concentrations, susceptible populations, and dose-response relationships will typically be limited and incomplete; thus in each of these areas decision makers confront considerable uncertainty. The decision framework can take such uncertainties into account by using probability distributions rather than single-number estimates for critical variables in the component models.

The framework uses decision tree methodology to consider the potentially uncertain variables judged to be most important: six that contribute to the overall uncertainty about health effects and one involving the control and monitoring costs associated with alternative standards. Of the six variables influencing health effects, there are two in each of the three relevant modeling stages.

- Ambient concentrations: (1) the particular frequency distribution describing concentration over time at a given location or set of locations; and (2) the extent of the area covered by a peak or near-peak concentration

- Exposure: (1) the number of sensitive people in a particular geographic area; and (2) the fraction of this sensitive population that is susceptible to health impairment at a given time because of the activity patterns of the individuals

- Health effects: (1) the relationship between air pollutant concentration (dose) and the fraction of the exposed susceptible population experiencing a physiologically observable health effect; and (2) the fraction of the population experiencing the physiologically observable health effect that also suffers a significant health impairment

Each of these variables may be represented as uncertain, with probabilities assigned to a set of alternative values that the variable may assume. Such probabilities may reflect data, expert judgment, or a combination of both. The decision tree provides a mechanism for combining the six uncertainties to assess the overall uncertainty in the extent and severity of health effects corresponding to a particular air quality standard. Alternative standards may then be compared in terms of their uncertain potential health effects and the costs (also uncertain) they will impose on society.

Implementation

The decision framework has been implemented as a computer program called FAST (framework for ambient standards tree). The program provides the capability to represent several geographic zones, time period types, sensitive population groups, and activity patterns. One or more health effects can be represented, and at the user's option, they can be separated into physiological effects and significant adverse health impairments. Ambient concentrations can be represented in any of three ways: a histogram of monitoring station data or results from an air quality model; a named frequency distribution (normal, lognormal, exponential, or Weibull) specified by given parameters; or a named frequency distribution whose parameters have been adjusted so that a given air quality standard is just met. This flexibility allows the user to evaluate both the current air quality situation and changes that might be required under a new standard.

FAST enables rapid sensitivity analysis by examining combinations of alternative values in the crucial variables described above. It also provides the capability for a probabilistic analysis that includes uncertainty in some or all of those crucial variables.

The program is written in ANSI Standard FORTRAN and is so structured that the component models may be modified or replaced without altering the overall structure of the program. It uses flexible, modular input files for the required data, and numerous options are available for displaying results. Summary results can be given as the actual number of health effect incidents or as the ratio of such incidents to total person-hours of exposure for the sensitive population. Detailed results can be provided for any desired combination of geographic zone, time period type, population group, activity pattern, and health effect category. Results for a probabilistic analysis using the decision tree are given as expected values and cumulative probability distributions; if desired, it is also possible to obtain an exhaustive listing of the number of health effects under each combination of assumed values or path through the decision tree.

The decision framework and associated computer software have been demonstrated on EPA's proposed addition of a new short-term ambient SO_2 standard. Consideration of this standard involves judgment about the extent and severity of health effects in a subgroup of the population, asthmatics engaged in vigorous exercise. The illustrative analysis was based on highly detailed air quality and demographic data for the region surrounding a single power plant. These data were disaggregated into geographic zones and hourly time periods for weekdays, Saturdays, and Sundays. With FAST it was possible to input these data and perform a basic analysis in less than a day. The analysis was then expanded to include uncertainty and more complex assumptions for the dose-response relationship. Representative calculations are described in the project's final report.

The goal of RP2141-2 has been the development of a framework that will be useful to the utility industry and to government policymakers responsible for establishing ambient air quality standards. The project has examined one current proposal for a new standard to demonstrate the resulting methodology and computer program. The FAST program will be available this summer through the Electric Power Software Center and the EPRI TEAM–UP Software Library. The final report, also available this summer, will include a user's guide with instructions for setting up and running the program. *Project Manager: Dennis Fromholzer*

R&D Status Report
ENERGY MANAGEMENT AND UTILIZATION DIVISION

Fritz Kalhammer, Director

FIRST-GENERATION FUEL CELLS

The main objectives of EPRI's fuel cell research are to expedite the commercial introduction of first-generation phosphoric acid fuel cells capable of achieving heat rates near 8000 Btu/kWh and of using petroleum and coal-derived fuels in an environmentally acceptable manner for dispersed power plant applications; to develop the fuel cell components required to improve power plant heat rates to less than 7500 Btu/kWh; and to develop fuel cell systems for use with coal gasifiers. This report presents the status of first-generation fuel cell activities. Program and project background has been discussed in previous EPRI Journal *articles (the most recent is January/February 1982, p. 49).*

EPRI is supporting three major efforts to expedite the commercialization of first-generation phosphoric acid fuel cells.

- Installation and operation of a 4.5-MW net ac fuel cell module on the system of Consolidated Edison Co. of New York, Inc. (RP842)
- Definition of the commercial configuration of a water-cooled 11-MW net ac power plant for utility application (RP1777)
- Definition of an air-cooled 7.5-MW gross dc power plant (RP2192)

The project at Consolidated Edison Co. of New York, Inc., demonstrates the installation, operation, and evaluation of a 4.5-MW fuel cell module designed and fabricated by United Technologies Corp. (UTC). Project objectives are to demonstrate that fuel cells can be sited, installed, operated, and maintained by utility personnel and to verify power plant characteristics, such as heat rate, reliability, reduced emissions, safety, and compatibility with the existing utility system. The 4.5-MW demonstration plant's fuel-processing, air supply, ancillary, and control systems are now being checked out before being integrated with the fuel cell stack modules.

A major incident last year delayed plant startup by approximately one year. Startup was suspended on March 19, 1982, when four reformer tubes in the fuel processing system were discovered to have been damaged by improper operation of the reformer startup burners. UTC, Consolidated Edison, and EPRI investigated the incident and identified its cause. All reformer repairs and modification have been completed and the power plant's fuel processing system successfully made hydrogen on April 1, 1983. All system startup tests are nearly complete, and the plant is scheduled to produce electricity by early August. A second 4.5-MW power plant, purchased from UTC by Tokyo Electric Power Co., has successfully completed all system startup tests and operated at 2 MW for over 12 hours during its first day of operation. (EPRI is not involved in the Tokyo project.)

UTC has made significant progress during the past two years in upgrading the 4.5-MW demonstrator to a commercially viable, water-cooled 11-MW configuration (called fuel cell generator-1, or FCG-1). EPRI has sponsored work to develop a less complex system design and to verify the performance and durability of key power plant components (RP1777-1).

Power plant performance was optimized against system operating pressure, fuel cell area, and capital cost. System trade-off

Table 1
FIRST-GENERATION FUEL CELL CHARACTERISTICS

	Demonstrator	Commercial Configuration
Module size (MW)	4.5	11
Power range (%)	25–100	30–100
Heat rate (Btu/kWh)	9300	8300
Fuel	Naphtha, natural gas, synthetic natural gas	Natural gas, light petroleum distillates, coal distillates, synthetic natural gas, liquefied petroleum gas, medium-Btu gas, methanol
Projected life (yr)	20*	30†
Startup time (h)	4	4
Plant footprint (acres)	0.8	1.2
Exhaust emissions (lb/10^6 Btu)		
NO_x	0.020	0.035
SO_x	0.00003	0.0003
Smoke	(none)	(none)
Projected cost ($/kW)‡	1200	600
Projected O&M cost (mills/kWh)	4–5	3–4

*Book life, with cell stack replacement every 40,000 hours.

†Book life, with 10% of stacks replaced each year, beginning after 40,000 hours.

‡In 1981 dollars, not including interest during construction and installation; assumes a production rate of 1500 MW/yr.

studies showed that by increasing the plant operating pressure from 50 to 120 psia (345 to 827 kPa), the power rating could be increased to 11 MW without significantly affecting the demonstrator process design. Other studies showed that by increasing the fuel cell area from 3.7 to 10 ft² (0.3 to 0.9 m²) per cell, the power rating could be achieved at a reduced cost. System simplification studies reduced the number of system components by 37%. Several major simplifications and improvements were achieved.

- Use of single-stage fuel vaporization
- Use of isothermal hydrodesulfurization
- Elimination of air-to-fuel heat exchangers
- Elimination of anode exhaust condensing
- Elimination of phosphoric acid scrubbers
- Use of electric heater for steam system startup
- Use of contact coolers and direct air-cooled fin-fan units for water recovery
- Use of commercial heat exchangers and rotating equipment

During the past year the FCG-1 conceptual design has progressed to the preliminary design stage. System process and instrumentation diagrams, component specifications, and steady-state and transient performance projections were prepared as a basis for more detailed design work. UTC is also verifying the performance and endurance of a full-scale, high-pressure reformer tube (RP1777-1). A 1000-hour endurance run conducted at the higher-pressure FCG-1 conditions was completed in February 1983.

There are several other related projects. A major fuel cell technology and scale-up effort (sponsored by DOE) will allow UTC to manufacture 10-ft² (0.9-m²) fuel cell components, compared with the 3.7-ft² (0.3-m²) components used in the demonstrator. Niagara Mohawk Power Corp. is performing the verification tests of commercial turbocompressor equipment. Tennessee Valley Authority is assessing system design changes that will enable the FCG-1 to use clean coal-derived fuels.

These coordinated efforts have resulted in an 11-MW power plant design, which has an 8300 Btu/kWh heat rate, multifuel capability, modular truck-transportable components, and a two-year installation time. Table 1 summarizes FCG-1 power plant characteristics. The estimated cost reductions associated with improved stack technology, system simplifications, and the extensive use of commercial components have lowered the specific cost for the first production unit by more than 50% relative to the 4.5-MW demonstrator. A commercial 11-MW fuel cell configuration is illustrated in Figure 1.

Electric utilities, represented by the Fuel

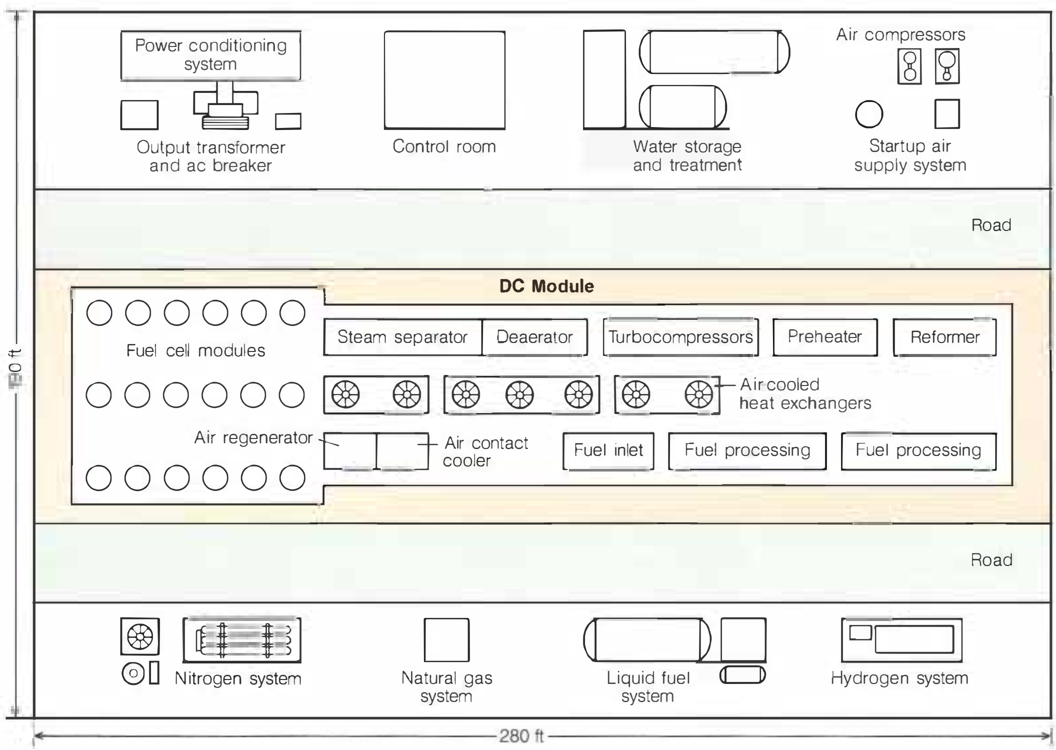


Figure 1 A generic 11-MW power plant configuration can be sited on ~1.2 acres. The dc module, located on the center aisle, is the heart of the power plant. Here the fuel cell modules, fuel processing, air supply, and steam system components are located. Ancillary systems are arranged along the perimeter of the dc module. Two roadways are provided to allow for the quick installation of the 11 truck-transportable pallets. Adequate space is provided for component access and maintainability.

Cell Users Group, have made an important contribution to the development of the commercial configuration. This, coupled with the experience gained from the 4.5-MW demonstrators, has resulted in a commercial concept designed for improved component access and easier maintainability; the plant footprint occupies ~53,000 ft² (4925 m²), or about 1.2 acres. EPRI will continue to support the UTC effort this year, which will emphasize fuel processing (reformer) design, development, and verification. This work will complement the UTC commercialization strategy, which calls for the installation of several 11-MW power plants by 1987–1988.

Westinghouse Electric Corp. is developing a 7.5-MW fuel cell power plant to compete with the UTC units. Westinghouse is a licensee of Energy Research Corp.'s air-cooled phosphoric acid technology; the Westinghouse–ERC team has been working together since 1978 to develop phosphoric acid fuel cell power plants.

The Westinghouse program (sponsored by DOE) is developing initial technology and systems to establish fuel cell performance, endurance, and manufacturability and will result in the design and fabrication of two 7.5-MW fuel cell power plants. Two electric utilities have expressed an interest in hosting the prototype plants. Program sponsors include Westinghouse, EPRI, the Empire State Electric Energy Research Corp., and the two host utilities.

Westinghouse's approach is to build the two prototypes as close to a commercial design as possible, to correct any system deficiencies during operation on utility systems, and then to offer commercial units of that design for sale. Power plant goals for a commercial plant include ~8000 Btu/kWh heat rate, multifuel capability, modular truck-transportable components, and a projected capital cost of ~$700/kW (1981 $).

Westinghouse has made significant progress during the past year in establishing manufacturing and test facilities to produce limited quantities of fuel cell components and stacks: the design, fabrication, and test of a 50-cell (10-kW) stack; preliminary design of a 400-cell (100-kW) stack; and the conceptual design of a 1600-cell (375-kW) module. The 375-kW module is the basic building block in the 7.5-MW power plant.

EPRI has participated in defining power plant and system design requirements; fuel processor system design, development, and verification; and power conditioning system design and verification (RP2192-1). During the past year, preliminary plant and system level design requirements were defined, and the conceptual design for a 7.5-MW power plant was prepared. EPRI support in the Westinghouse effort will continue this year; a detailed plant preliminary design will be initiated, as well as fuel processing and power conditioning system design and verification. *Project Manager: D. M. Rastler*

DEUS EVALUATION TOOLS

In early 1979 EPRI initiated research (RP1276) to evaluate alternative dual energy use systems (DEUS) and to identify attractive applications for these systems (EPRI Journal, *November 1981, p. 53). DEUS simultaneously produce electricity and useful thermal energy, allowing utilities and their industrial customers cooperatively to increase their fuel efficiency and to expand generating capacity. In the past year a pair of analytic computer models have been developed to help utilities assess DEUS participation: the DEUS computer evaluation model (DEUS model) and a cogeneration options evaluation model (COPE model). In addition, new conceptual cogeneration system designs have been developed to assess DEUS projects in enhanced oil recovery. A conceptual design in the pulp and paper industry is complete, and conceptual system designs in the distillation and industrial park industries are now being developed. Other research includes evaluating district heating technologies and site-specific district heating applications and establishing a cogeneration data base.*

DEUS and COPE computer models

General Electric Co. developed the DEUS model for EPRI, and over two dozen utilities and engineering consultants now use the model for site-specific cogeneration design, costing, performance evaluation, and economic analysis. The model may be used to screen potential cogeneration applications; select and specify preferred cogeneration equipment and configurations; evaluate the effects of cogeneration installation on the serving utility; analyze performance, cost, and benefits of a cogeneration plant design and compare it with a conventional system; assess the impact of power and steam contracts; and determine the cogeneration potential for an entire service area.

The DEUS model incorporates its own cogeneration data base, which contains generic cost and performance information useful for screening analyses. Nine energy conversion systems (ECS), including the no-cogeneration boilers, are now represented in this data base. The model can evaluate DEUS configurations incorporating up to four fuel streams, all fueling a single ECS. The ECS may be sized to the availability limit of its fuel stream, to site steam requirements, or to meet a user-specified power rating. The model can also evaluate industrial, utility, or third-party ownership, as well as options of selling only excess electricity to the utility or selling all cogenerated power with buy-back of site power.

The DEUS model is most useful as a screening tool to determine if more detailed feasibility studies are warranted. However, if properly detailed cost and performance input data for specific cogeneration systems are prepared, more sophisticated evaluations can be performed.

The COPE model was developed by Synergic Resources Corp. to complement the DEUS model. It analyzes financial impacts and evaluates institutional and regulatory aspects of proposed cogeneration ventures. COPE evaluates ownership structure (e.g., utility, industry, third party, joint venture, partnership), operating mode, and electricity sales arrangements to produce an after-tax cash flow analysis for each project participant. This analysis is based on detailed, site-specific information, and it considers all practical combinations of ownership and operation.

Both the DEUS and COPE models have tested more than 150 conceptual designs and are now available through the Electric Power Software Center. DEUS program descriptive and user's manuals are also available. The descriptive manual details the model's structure, applications, methodology, validation, and associated data base (EM-2776, Vol. 1); the user's manual explains how to access the model, prepare data to analyze cogeneration technologies, and interpret results (EM-2776, Vol. 2). Similar manuals for COPE are forthcoming.

Cogeneration with enhanced oil recovery

In the past year EPRI's cogeneration system research focused on enhanced oil recovery (EOR). With the increased cost of oil, EOR has become increasingly economic as a means of recovering oil from domestic fields that are becoming depleted. One of the most widely used EOR methods, and one expected to continue to grow, is the injection of steam into reservoirs of heavy oil or tar sands to lower resource viscosity and make it easier to extract. Increased application of EOR complements growing electric power demands and makes the use of cogeneration with enhanced oil recovery attractive.

EOR cogeneration systems promise to help utilities level peak loads because steam supply need not be maintained on a 24-hour basis, which allows these systems to generate power during peak periods. As much as 17 GW could be cogenerated by 1990 if all process steam were cogenerated (EM-1966).

Cogeneration applications in EOR can be economically attractive to both the oil industry and the utilities. Some oil producers have already incorporated EPRI DEUS designs in initial cogeneration projects. For example, the Oil Shale Co. (Tosco) has installed a gas turbine with a heat recovery boiler at a site near Newhall, California. This turbine will generate 7.2 MW, using steam at an average of 45,000 lb/h (5.7 kg/s) at 1000 psig (6.9 MPa). Full operation is expected in mid 1983.

EPRI selected two sites for conceptual design and analysis of EOR cogeneration systems (EM-2714): the Tosco site in southern California and a Conoco, Inc., site near Uvalde, Texas. A wide variety of possible cogeneration technologies and fuels were evaluated in selecting specific systems for detailed evaluation. Preliminary operating characteristics and cost estimates for a large number of alternative approaches were developed. Using the criteria of over 20% return on investment, over 75% energy efficiency, operational flexibility, and environmental acceptability, two gas turbine options were selected for detailed analysis at the Tosco site, and one coal-fired option was selected for the Conoco site.

Table 2 shows the results of analysis of these conceptual systems. The gas turbine–heat recovery boiler listed in the table is designed to provide in excess of 99% quality steam. The dual gas turbine–heat recovery boiler system, in which two gas turbines without supplementary firing exhaust into one heat recovery boiler, tended to maximize electric power generation, while maintaining net heat output to the field.

Two variations of the retrofit system option were evaluated at the Tosco site. The first (indirect air) recovers heat from the turbine exhaust for feedwater heating. It then recovers additional heat from the turbine exhaust by means of an air-to-air heat exchanger for preheating combustion air. The second (direct air) also recovers heat from the turbine exhaust for feedwater heating, but then directly injects the turbine exhaust into the two conventional steam generators to provide hot combustion air.

For this analysis, the indirect air system was favored on the basis of its ability to maintain a lower turbine pressure and greater power production. The indirect-air retrofit system was further analyzed with a steam topping turbine added to generate electricity from steam on its way to the field. This option would be applicable where the required pressure for steam to the field is relatively modest, but not for situations in which higher pressures were needed for the field. The steam topping turbine increased electric power substantially with minimal reduction in steam supply.

At the Conoco site, the availability of low-cost coal and lignite and the prospect of a petroleum coke by-product for future operations influenced technology selection. Because the Conoco site technology is based on the use of low-cost solid fuels and waste products, this project interested many oil producers and local utilities. Large quantities of crude oil now used to generate steam for EOR could be marketed elsewhere if low-cost alternative fuels were available.

The fluidized-bed approach was selected for detailed study at the Conoco site because the method could be carried out as early as 1985. The concept evaluated uses a recirculating system that results in a high degree of combustion efficiency and good emissions control. A recirculating system allows location of the hot air tubes in a separate element of the system, called the air heater or heat exchanger, which alleviates metallurgical problems caused by placing the air tubes in the primary combustor. However, because the fluidized-bed and turbine designs analyzed in this option are still evolving, confident estimation of their costs has been difficult.

Table 2
ANALYSIS OF ENHANCED OIL RECOVERY COGENERATION DESIGNS

Site and Concept	Net Electricity Output (MW)	Steam to Field (million Btu/h)	Internal Rate of Return (%)	Payback (years)
Tosco site, Newhall, California				
Gas turbine–heat recovery boiler, supplementary firing	3.83	50	25.8	3.7
Dual gas turbine–heat recovery boiler, no supplementary firing	7.90	50	21.5	4.1
Gas turbine–conventional boiler retrofit (indirect air)	2.56	126	31.2	3.3
Gas turbine–conventional boiler retrofit (indirect air and topping turbine)	4.14	119	30.5	3.3
Conoco site, Uvalde, Texas				
W191D-based fluidized-bed hot-air cycle system	195	1670	17.6	4.3
W501D-based fluidized-bed hot-air cycle system	223	1670	25.6	3.2

Other research

A district heating survey recently conducted for EPRI highlighted several problems with existing district heating systems in the United States and defined key technical and institutional differences between U.S. and European district heating systems and practices (EM-1436). An assessment of the current status of European technology for district heating turbines, distribution networks, and piping technology has been completed (EM-2864).

Additional research is evaluating site-specific district heating system designs using European technology for three utilities (RP1276-5). Sites have been chosen at Providence, Rhode Island; Springfield, Massachusetts; and Lansing, Michigan. This project is scheduled to be completed by December 1983.

EPRI has established a data base of more than 580 existing and 400 possible industrial cogenerators, which gives each facility's location; industrial classification; equipment; fuel input; and mechanical, thermal, and electric energy output. EPRI expects to make this resource available for cogeneration trend analysis this year. The cogenerators identified in the data base have a total generating capacity in excess of 15,000 MW, or about 3.5% of the existing installed U.S. electric power generation capacity. *Project Manager: S. David Hu*

R&D Status Report
NUCLEAR POWER DIVISION

John J. Taylor, Director

STEAM SURFACE CONDENSERS

In recent years considerable attention has been given to improving the design and operation of steam surface condensers. Laboratory and plant testing has demonstrated that the major source of corrodents in power plant secondary systems is the leakage of cooling water and air into the steam side of the condenser. From there, impurities travel via the steam condensate and feedwater to the steam generators and turbines.

The initial application of steam as a source of power in the eighteenth century involved engines from which the steam was exhausted at subatmospheric pressure. At first, the exhaust steam was condensed in a direct-contact heat exchanger (often called a jet or barometric condenser) into which river water was introduced. The mixing of the steam with raw water precluded reuse of the condensate. Later, when surface condensers were adopted, it became possible to achieve a higher level of condensate purity and to employ chemical treatment to minimize corrosion in the feedwater heating system and the boilers. Surface condensers have been in widespread use for over 60 years, during which time improvements in integrity have been a continuing goal.

Steam turbine inlet pressure and temperature have increased greatly over the past half century, and condenser requirements now include maintenance of the lowest feasible exhaust pressure (and thereby the lowest heat rejection temperature), recovery of the steam condensate with minimum contamination by the cooling water, and removal of gases from the condensate (to a level of only a few parts per billion [ppb]) in a vacuum environment.

Corrosion-related problems experienced by steam generators and turbines have resulted in high costs and significant reductions in plant availability. Plant experience has clearly demonstrated the incentives for minimizing the amount of aggressive impurities introduced into the feedwater by leakage of cooling water and/or air into the condenser.

Cooling-water inleakage

Ingress of cooling water into the condensate has long been recognized as deleterious to the availability and life expectancy of steam power plants. The occurrence of rapid corrosion in some PWR steam generators has resulted in R&D to provide utilities with improved leak detection capability and, more important, leak location capability to enable remedial action. As reported in NP-2597, a system for monitoring condenser inleakage has been developed and tested (Figure 1). Using helium as a tracer gas, the system is able to detect cooling-water leakage at rates of 0.56 ml/min (1.5×10^{-4} gal/min). Nondestructive examination (eddy-current) techniques are now being widely used for condenser tubing inspection.

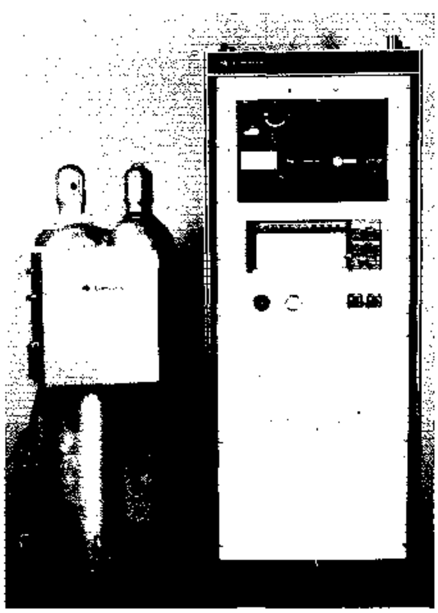


Figure 1 Instrument module and tracer gas tanks for the condenser inleakage monitoring system. A section of the condenser is taken out of service, and the tracer gas is released into the water side of the tubing; the instrument module is then used to locate cooling-water leakage paths by measuring the tracer in the offgas from the steam side.

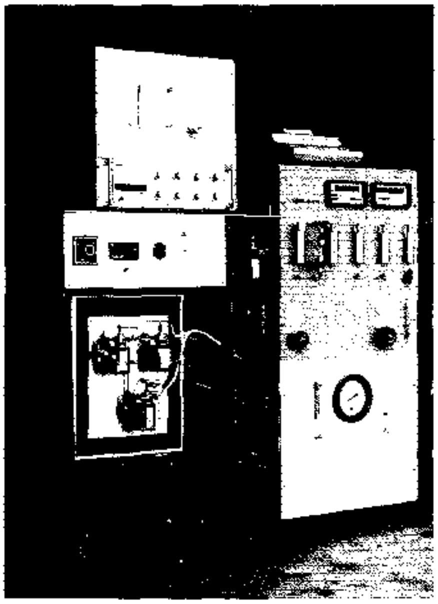
For new or retrofit condensers, many utilities around the world are upgrading condenser design and tubing materials to reduce the likelihood of cooling-water ingress during plant operation.

Deaeration

The large, cold surface area of the tubing in a condenser tends to subcool the steam condensate as it is formed, with the result that gases are driven into aqueous solution. The primary concern in terms of corrosion is dissolved oxygen, whose reaction with condenser and feedtrain materials leads to the transport of reducible metal oxides to the steam generators. In particular, copper oxides have been shown to be very strong oxidizers. The ability to minimize dissolved oxygen in the condensate depends partially on the tube field arrangement and the thermal load, but more directly on the ratio of installed air removal capacity to the rate of air inleakage.

It is necessary to remove significant quantities of steam with the air (noncondensables) in order to limit the partial pressure of air in the condenser. For a minimum level of dissolved oxygen (7 ppb), domestic manufacturers specify that the ratio of removal capacity to inleakage be approximately seven. In most operating plants, this specification requires operators to use tracer gas tech-

Figure 2 Prototype dissolved-gas analysis system for monitoring air leakage into condensers. This system uses gas chromatographic techniques to detect sub-ppb levels of gases in water samples.



niques (similar to those used for cooling-water leakage) to locate and repair air leaks.

A monitoring system (Figure 2) has been developed that permits the on-line detection of sub-ppb concentrations of such dissolved gases as oxygen, nitrogen, and argon to provide mass balances relating to corrosion (NP-2865). Argon is particularly useful to monitor as a tracer because it is a naturally occurring constituent of air and is nonreactive. In-plant testing of the system enabled operators to make significant reductions in air leakage.

R&D is planned to evaluate methods of improving the deaerating capability of condensers at no-load and low-load conditions (RP1689). *Project Manager: R. L. Coit*

CHARACTERIZATION OF ULTRASONIC SYSTEMS

In response to the growing need for calibration and characterization of ultrasonic systems used in the nuclear industry, EPRI's Nondestructive Evaluation (NDE) Center has established an ultrasonic calibration laboratory. The laboratory is capable of performing routine calibration services, traceable to the National Bureau of Standards, as well as quantifying the performance characteristics of ultrasonic components and systems.

As a result of NRC Regulatory Guide 1.150 ("Ultrasonic Testing of Reactor Vessel Welds During Preservice and Inservice Examinations") and several other, independent investigations, the need for characterization and documentation of systems used for ultrasonic inspection has become apparent. In several instances it has been shown that ultrasonic systems of the same nominal specifications do not provide equivalent performance. A major objective of the NRC guide is a demonstration of the reproducibility of test results. It is doubtful that this objective can be achieved without documentation of component and system performance parameters.

Characterization approach

An ultrasonic system has three major components: a pulser or transmitter, a transducer and cable, and a receiver. The components interact with one another, as well as with the laboratory test reflector, to yield a characteristic system output. These interactions are not necessarily linear. To achieve the goal of reproducibility, it is necessary to document the performance characteristics of the component parts as well as the overall system response.

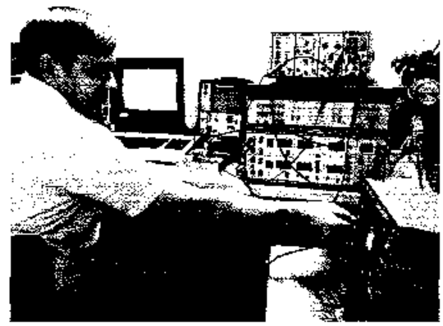
The pulser, which is the electronic circuitry used to excite a transducer, is in general the most nonlinear component of the system. However, its major characteristics—output impedance, spectral content, peak voltage, and pulse shape—can be measured. In the laboratory characterization, these output parameters are measured with resistive loads of 10 and 100 ohms.

The transducer is the most variable component and the one most likely to change with use. Transducer characteristics that are measured include peak frequency, upper and lower frequencies (−6 dB from peak), bandwidth center frequency, percent bandwidth, radio-frequency waveform, impedance, insertion loss or relative loop sensitivity, active element diameter or size (beam size at contact surface for a transducer designed to operate on plastic shoes), beam pattern in water, and beam spread in water.

Frequency, impedance, and sensitivity parameters are determined on the basis of the reflection from a large planar reflector immersed in water at a distance of 2 in (5.08 cm) or less. Beam pattern parameters are mapped in water by using a miniature hydrophone or ball reflector. A system capable of mapping sound beams in steel is expected to be operational this year.

The receiver section of a system is basically an amplifier, and its characterization is straightforward. Receiver parameters that are measured include band pass, noise, sensitivity, and linearity. The results are displayed in graphic and/or tabular form.

Figure 3 Laboratory equipment at EPRI's NDE Center enables the characterization of ultrasonic testing systems, an important step toward ensuring the reproducibility of test results.



The final step in the process is the characterization of the assembled system. This requires that the instrument have a radio-frequency output. The spectral content and the waveform are recorded by using a large flat reflector at a distance of either 2 in (5.08 cm) or the nominal near-field length, whichever is less. This check provides assurance that the system components operate compatibly and as expected on the basis of individual component testing.

Instrument controls for damping, pulse length, frequency, filtering, and other features can have considerable influence on performance characteristics. The influence of such control settings can be evaluated at both the component and system levels. Figure 3 shows the characterization equipment being used to quantify the performance features of an ultrasonic testing system.

Services

The EPRI NDE Center calibration and characterization laboratory is now operational. The equipment and procedures were used to characterize ultrasonic systems in connection with round robin tests completed at the center last summer as part of U.S. participation in the Program for Inspection of Steel Components (PISC-II). More recently, the laboratory has been used for utility inservice inspection systems.

The NDE Center is prepared to perform calibration and characterization of ultrasonic equipment for utilities, their service contractors involved in NDE activities at commercial nuclear reactors, and NDE research and development organizations. This service will be offered on a cost-recovery basis. For further information contact B. Knipschield, EPRI NDE Center, (704) 597-6199. *Project Manager: Gary Dau*

New Contracts

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
Advanced Power Systems				
RP832-11	Two-Stage Coal Liquefaction Process Analysis	3 months	71.4	The Lummus Co *N. Hertz*
RP1319-12	Evaluation of Combustion Liner Configuration	8 months	73.9	United Technologies Corp. *A. Cohn*
RP1597-1	Evaluation of Irradiated Metal Samples for Use in Fusion Components	1 month	25.0	McDonnell Douglas Astronautics Co. *K. Billman*
RP2103-1	Gas Turbine Performance Recovery Methods: Operation, Maintenance, and Repair Techniques	11 months	300.8	Energy Services Inc. *R. Duncan*
RP2146-3	Development of Homogeneous Catalysts for the Preparation of Methanol From Coal-Derived Synthesis Gas	7 months	100.0	Brookhaven National Laboratory *N. Hertz*
RP2195-1	Analysis of Conversion Cycles for Geothermal Wellhead Power Systems	5 months	30.0	United Technologies Research Center *E. Hughes*
RP2221-2	Low-Purity Oxygen Production for Coal Gasification–Based Power Systems	5 months	25.0	Cryogenic Consulting Service, Inc. *T. O'Shea*
RP2388-1	Evaluation of Performance: Gas Turbine Blade Coatings	5 months	89.3	Solar Turbines, Inc. *R. Duncan*
RP2421-1	Gas Turbine System Diagnostics Development	37 months	532.0	Battelle Memorial Institute *C. Dohner*
Coal Combustion Systems				
RP1404-5	Recovery of Alumina and Other Strategic Minerals From Fly Ash	8 months	50.0	Union Carbide Corp. *D. Golden*
RP1681-1	Power Plant Performance Monitoring	6 months	187.5	Potomac Electric Power Co. *F. Wong*
RP1850-2	Medium Volume/ Medium Technology By-Product Utilization	5 months	74.0	Michael Baker, Jr., Inc. *R. Komai*
RP1887-2	High-Reliability Feedwater Heater Study	18 months	166.8	Heat Exchanger Systems, Inc. *I. Diaz-Tous*
RP1957-2	Photothermal Radiometric Imaging for Turbine NDE	1 year	75.8	Arizona State University *A. Armor*
RP1957-3	Turbine Erosion Measurement by Thin-Layer Activation	6 months	71 6	Spire Corp. *A. Armor*

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP1961-4	Innovative Continuous Emission Monitoring Techniques	9 months	53.7	Acurex Corp. *C. Dene*
RP2190-2	Feasibility, Design, and Operation of the Sumner County Solid-Waste Energy Recovery Facility	14 months	125.0	Tennessee Valley Authority *C. McGowin*
RP2305-1	Inquiry on Japanese Coal-Fired Power Plant Performance	2 months	33.0	Bechtel Group, Inc. *A. Armor*
Electrical Systems				
RP2148-2	Fast Voltage Estimation Computer Program, Phase 1	17 months	356.0	Systems Engineering for Power, Inc. *J. Mitsche*
RP2149-1	Enhancement of the Electromagnetic Transients Program; Phase 1, Technical Assessment	13 months	115.8	Westinghouse Electric Corp. *J. Mitsche*
RP2153-1	Power Plant Performance Instrumentation System	6 months	187.5	Potomac Electric Power Co. *J. Lamont*
RP2308-3	Stator Slot Wedge Tightness Measurement Instrument	6 months	48.1	Vintek, Inc. *D. Sharma*
RP7895-1	Oil Deterioration Procedure to Monitor the Condition of High-Voltage Oil-Filled Paper Cables	40 months	580.4	Detroit Edison Co. *T. Rodenbaugh*
Energy Analysis and Environment				
RP1152-12	Industry and Economy Implications of Restrictions in Generation Capacity	9 months	35.3	Dale W. Jorgenson Associates *V. Niemeyer*
RP1484-14	Application of Decision Analysis to the Use of Probability Risk Assessment Results	3 months	46.0	Decision Focus, Inc. *D. Fromholzer*
RP1829-4	Economic Estimates of Ecologic Damage	1 year	60.6	Energy Resource Consultants, Inc. *R. Wyzga*
RP2143-1	Planning R&D Options for Meeting Peaking and Cycling Requirements	9 months	199.2	Decision Focus, Inc. *L. Rubin*
RP2145-1	Residential End-Use Load Shapes	17 months	311.2	Scientific Systems, Inc. *S. Braithwaite*
RP2279-2	Short-Run Utility Sales Forecasting	6 months	46.8	Quantitative Economic Research, Inc. *L. Williams*

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP2381-1	Load Management—Conservation Newsletter	4 months	29.5	Synergic Resources Corp. *C. Hakkarinen*

Energy Management and Utilization

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP1085-9	Modeling of Internal Methane Reforming in Molten Carbonate Fuel Cells	7 months	43.1	Physical Sciences, Inc. *A. Appleby*
RP1086-15	Laboratory Test of Prototype SLX Process	4 months	50.1	Lawrence Berkeley Laboratory *B. Mehta*
RP2035-5	Design of Residential Load Control Experiment	8 months	40.5	Cyborex Laboratories *V. Rabl*
RP2038-3	Evaluation and Correlation of Acoustic Flow Measurement System	18 months	236.4	Chas. T. Main, Inc. *C. Sullivan*
RP2285-1	Visual Effectiveness of Combined Daylight and Electric Lighting Systems	7 months	70.0	Illuminating Engineering Research Institute *A. Lannus*
RP2285-3	Daylight Sensing Photocell Placement	10 months	85.5	Lawrence Berkeley Laboratory *A. Lannus*
RP2416-2	Metal Fabrication Program Development	6 months	50.7	Battelle, Columbus Laboratories *L. Harry*
RP2416-4	Meeting: Petroleum Process Application	7 months	50.0	Science Management Corp. *L. Harry*
RP2416-6	Program for Continuing Research on Electricity-Based Textile Processes	3 months	30.0	Georgia Tech Research Institute *L. Harry*

Nuclear Power

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP1163-10	Accident Analysis With MMS	5 months	59.5	General Electric Co. *M. Divakaruni*
RP1842-6	Use of RETRAN for Success Criteria Determination	4 months	56.0	Energy, Inc. *B. Chu*
RP2163-1	Intergranular Stress Corrosion Cracking of Alloy 600 Tubes; Development of a Predictive Model, Phase 1	5 months	32.9	S. Levy, Inc. *A. McIlree*
RP2170-5	Sensitivity Studies of Seismic Risk Models	4 months	42.1	Structural Mechanics Associates, Inc. *D. Worledge*
RP2181-3	Influence of Irradiation and Stress on the Behavior of Structural Materials	37 months	328.2	Kraftwerk Union Ag *A. McIlree*
RP2232-1	Automated Nuclear Plant Maintenance	5 months	84.0	Battelle, Columbus Laboratories *T. Law*
RP2233-1	Key Valves; Prioritization Study	5 months	102.2	Burns and Roe, Inc. *B. Brooks*
RP2240-1	Oxidation Studies of Spent Fuel Rods in Air	29 months	135.8	Department of Energy *R. Lambert*
RP2254-1	In-Situ Calibration of Resistance Temperature Detectors	18 months	215.0	Union Carbide Corp. *G. Shugars*
RP2296-1	Feasibility of Nonchemical Fuel Rod Decontamination	4 months	67.9	NUS Corp. *H. Ocken*
RP2299-1	Critical Two-Phase Flow in Small-Break Loss-of-Coolant Accidents	9 months	32.1	Dartmouth College *J. Sursock*
RP2347-2	Monitoring Automated BWR Emergency Procedures	3 months	41.5	S. Levy, Inc. *D. Cain*
NP2353-1	Modeling BWR and PWR Separators by Using ATHOS Code	11 months	42.9	Wang Software Service *G. Srikantiah*
RP2356-1	Technical Support of Research Program on Eastern U.S. Seismology and Charleston Earthquake	3 months	33.6	Woodward-Clyde Consultants *Y. Tang*
RP2392-2	Test Contractor Q/A Program Development	18 months	32.0	S. Levy, Inc. *J. Hosler*
RP2392-4	PWR Degraded Core Analysis Sensitivity Studies	5 months	90.0	Jaycor *G. Thomas*
RP2392-6	BWR Degraded Core Analysis Sensitivity Studies	5 months	54.9	S. Levy, Inc. *G. Thomas*
RP2411-2	Passivation, Surface Finish, and Prefilming Survey	6 months	27.1	Advanced Process Technology *C. Wood*
RP2420-2	RETRAN Analysis Support for the Pressurized Thermal Shock Program	10 months	40.0	Energy Incorporated *B. Chexal*
RP2430-1	Support of Plant Cost Analysis for Large-Scale Prototype Breeder	4 months	44.0	Boeing Engineering and Construction Co. *C. Gibbs*
RP2430-6	Institutional/Financial Planning for the Design, Construction, and Operation of a Near-Commercial-Scale LMFBR Plant	2 months	40.0	Kidder, Peabody & Co., Inc. *C. Gibbs*

R&D Staff

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP1871-7	Effect of SO_2 Scrubber Chemistry on Corrosion	13 months	200.1	Rockwell International Corp. *B. Syrett*

New Technical Reports

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

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

Requests for copies of specific reports should be directed to Research Reports Center, P.O. Box 50490, Palo Alto, California 94303; (415) 965-4081. There is no charge for reports requested by EPRI member utilities, government agencies (federal, state, local), or foreign organizations with which EPRI has an agreement for exchange of information. Others in the United States, Mexico, and Canada pay the listed price. Overseas price is double the listed price. Research Reports Center will send a catalog of all EPRI reports on request. Microfiche copies are also available from Research Reports Center, at the address given above. The price per volume of $6.00 in the United States, Canada, and Mexico and $12.00 per volume overseas includes first-class postage.

Standing orders for free copies of reports in EPRI program areas or Technical Summaries of reports for each EPRI technical division may be placed by EPRI member utilities, libraries of U.S. federal, state, and local government agencies, and the official representative of any foreign organization with which EPRI has an information exchange agreement. For details, write to EPRI Technical Information Division, P.O. Box 10412, Palo Alto, California 94303.

ADVANCED POWER SYSTEMS

Photovoltaic Requirements Estimation: Simplified Method

AP-2475 Final Report (RP1975-3); $14.50

This report presents a simplified single-year analysis method for evaluating the economics of photovoltaic (PV) systems for central station applications. Details are provided on (1) a computer code developed to determine the fuel and variable operations and maintenance savings attributable to a PV system for a single year, and (2) a method developed to represent PV system and module cost-performance trade-offs. The contractor is Science Applications, Inc. *EPRI Project Manager: R. W. Taylor*

Combustion Evaluation of Residual Fuel Oil From Two-Stage Liquefaction

AP-2845 Final Report (RP1412-5); $11.50

Laboratory tests were performed to evaluate the combustion and emissions characteristics of a residual fuel oil produced by two-stage coal liquefaction. Combustion variables examined include furnace excess oxygen, fuel atomization, burner stoichiometry, combustion air swirl, and boiler load. In general, the tests indicated the residual fuel oil burns well, with flame characteristics similar to those of No. 6 fuel oil. The contractor is KVB, Inc. *EPRI Project Manager: W. C. Rovesti*

Combustion Engineering Two-Stage, Atmospheric Pressure, Entrained-Flow Coal Gasification PDU Program

AP-2846 Final Report (RP244-1); $31.00

This report documents a program to design, construct, and test a two-stage, atmospheric pressure, entrained-flow, low-Btu gasification process development unit (PDU). Also described is a mathematical model developed to provide a basis for scale-up to commercial-size gasifiers; data from the PDU tests were used to calibrate the model. The major process concepts and gasifier design features are defined, and economic analyses are discussed. The contractor is Combustion Engineering, Inc. *EPRI Project Manager: G. H. Quentin*

Technical and Economic Evaluation of Retrofitting and Repowering Oil-Fired Boilers With Gas From Coal

AP-2854 Final Report (RP1660-1); $25.00

This report discusses a conceptual engineering design and cost study of the feasibility of (1) substituting fuel gas from coal for oil fuel at a modern oil-fired steam plant, and (2) using fuel gas from coal as the combustion turbine fuel (and also, in some cases, as the boiler fuel) in a repowered version of the same plant. The contractor is Fluor Engineers, Inc. *EPRI Project Manager: B. M. Louks*

Gas Turbine Evaluation (GATE) Computer Program

AP-2871-CCM Final Report (RP2052-1); $13.00

This report describes the development of GATE, a computer program for calculating detailed gas turbine power plant performance characteristics. It includes the initial documentation and discusses different power plant cycle options, the engineering approach and methods used, and sample cases to demonstrate applications. The contractor is Mark Waters and Associates, Inc. *EPRI Project Manager: Arthur Cohn*

Assessment of Distributed Wind Power Systems

AP-2882 Final Report (RP1271-1); $28.00
AP-2882-SY Summary Report; $10.00

These reports document a two-year project to develop methods for evaluating the performance, economics, utility system impacts, and penetration limits of distributed wind power generation relative to central station wind power generation. Planning methods, a generation study, and transmission and distribution analyses are described. The final report is intended for a technical audience and the summary report for a general audience. The contractor is General Electric Co. *EPRI Project Managers: F. R. Goodman, Jr., and E. A. DeMeo*

EPRI Conference Proceedings: Solar and Wind Power, 1982 Status and Outlook

AP-2884-SR Special Report; $22.00

This report contains the proceedings of the 1982 EPRI Review of Solar and Wind Power Technologies, which was held in Providence, Rhode Island, in August. It covers key utility, EPRI, industry, and federal solar and wind power development programs. The contractor is the University of Kansas Center for Research, Inc. *EPRI Project Manager: E. A. DeMeo*

COAL COMBUSTION SYSTEMS

Continuous Emission Monitoring in the Electric Utility Industry

CS-2860 Final Report (RP1961-2); $13.00

This report describes utility surveys, site evaluations, and an information-exchange meeting conducted to evaluate the state of the art of continuous emission monitoring (CEM) systems in electric utility fossil fuel plants. Regulatory and technical issues important to utility personnel who plan, design, and maintain CEM installations are addressed. The contractor is Kilkelly Environmental Associates, Inc. *EPRI Project Manager: C. E. Dene*

Measurements of POM Emissions From Coal-Fired Utility Boilers

CS-2885 Final Report (RP1075-1); $16.00

Emissions of polycyclic organic material (POM) from fossil fuel combustion systems were investigated. This report assesses the state of the art of POM sampling and outlines criteria for developing more suitable techniques. Recommendations for future utility POM measurement programs are presented. The contractor is KVB, Inc. *EPRI Project Manager: M. W. McElroy*

ELECTRICAL SYSTEMS

Selective Modal Analysis in Power Systems

EL-2830 Final Report (RP1764-8); $13.00

This report details the development and evaluation of the selective modal analysis (SMA) method for power system dynamic stability analysis. The method is compared with existing methods, and its distinctive features are examined—its identification of system variables significant in selected system modes and its use of SMA extensions for constructing dynamic equivalents of any power system. Computational results for a 39-bus system are included. The contractor is the Massachusetts Institute of Technology. *EPRI Project Manager: N. J. Balu*

HPOF Transmission System Economic Evaluation Program

EL-2833 Final Report (RP7884-1); $13.00

This report describes a sophisticated computer program for evaluating the economic operation and cost-effectiveness of high-pressure oil-filled (HPOF) pipe-type underground transmission cables. A detailed analysis of validation and application tests is presented that confirms the program's versatility. A review of currently available HPOF design options is included. The contractor is Systems Control, Inc. *EPRI Project Managers: S. Kozak and T. J. Rodenbaugh*

Electrohydrodynamic Pumping in Cable Pipes

EL-2834 Final Report (RP7871-1); $32.50

Analytic and experimental studies of electrohydrodynamic (EHD) pumping were conducted to examine its possible application in underground cable cooling. The objectives were to design, develop, and test a practical EHD pump; evaluate pumping speeds; further develop EHD pumping theory; and compare theory with practical results.

The contractor is the University of Illinois at Urbana-Champaign. *EPRI Project Managers: B. S. Bernstein and T. J. Rodenbaugh*

Transmission Line Structure Foundations for Uplift/Compression Loading

EL-2870 Final Report (RP1493-1); $31.00

The state of the art of foundation engineering for transmission line structures was assessed, with emphasis on uplift/compression foundation design loads. This report has a broad scope and covers many aspects of geotechnical, foundation, and structural engineering. Detailed research recommendations are included. The contractors are Cornell University and GAI Consultants, Inc. *EPRI Project Manager: P. G. Landers*

Comparison of Algorithms for Computing Generating-System Reliability Indexes

EL-2874 Final Report (TPS81-822); $14.50

This report describes a project that compared the accuracy of several approximation techniques for computing generating-system reliability indexes. The techniques considered are the method of cumulants, the distribution fitting method, the large-deviation procedure, and the Monte Carlo importance sampling procedure. Recommended procedures for use by the industry are indicated. The contractor is the University of Pittsburgh. *EPRI Project Manager: N. J. Balu*

Metal Oxide Surge Arresters for Gas-Insulated Systems

EL-2876 Final Report (RP1421-1); $29.50

The development of metal oxide surge arresters for gas-insulated systems is summarized. The basic characteristics of such arresters for 69, 138, 230, and 500 kV are described. The behavior of the arresters in typical power system applications is shown by computer calculations for lightning surges and switching operations. The expected effects of seismic activity and internal fault arcs are also discussed. The contractor is Brown Boveri Electric, Inc. *EPRI Project Manager: V. H. Tahiliani*

ENERGY ANALYSIS AND ENVIRONMENT

Precipitation Scavenging Chemistry for Sulfate and Nitrate From SURE and Related Data

EA-1914 Final Report (RP1630-1); Vol. 2, $10.00

This volume presents an analysis of aerometric and precipitation chemistry data collected in 1978 and 1979. The analysis includes an estimate of Junge's rainout efficiencies for sulfur and nitrogen oxides, which are directly related to washout ratios. Also illustrated is the informational value of combined aerosol and precipitation water data that include both cation and anion chemistry. The contractor is Environmental Research & Technology, Inc. *EPRI Project Manager: G. R. Hilst*

Assessment Methodology for New Cooling Lakes

EA-2059 Final Report (RP1488-1); Vol. 1, $22.00; Vol. 2, $13.00

This report evaluates multiple uses for new cooling lakes, with an emphasis on recreational fishing. Volume 1 describes a stepwise methodology for assessing the multiple-use benefits of cooling lakes. A sample test case is included. Volume 2 documents the statistical methods used to develop an empirical predictive model for cooling lake fisheries. Volume 3 (published earlier) presents limnological and fisheries data on U.S. cooling lakes, as well as a bibliography. The contractor is Tetra Tech, Inc. *EPRI Project Managers: R. K. Kawaratani and I. P. Murarka*

Evaluation of CHESS: Utah Asthma Study, 1971–1972

EA-2829 Final Report (RP1316-1); $16.00

This report evaluates the data sets from an EPA Community Health and Environmental Surveillance System (CHESS) study that examined the relationship between asthma and air pollution in the Salt Lake Basin region. The report reviews the use of asthma as a health indicator in environmental epidemiology, considers the impact of data quality, and presents statistical analyses. The contractor is Battelle, Pacific Northwest Laboratories. *EPRI Project Manager: R. E. Wyzga*

Air Pollution Damage to Man-Made Materials: Physical and Economic Estimates

EA-2837 Final Report (RP1004-1); $11.50

This report describes a study of the damage to paint, galvanized steel, and structural concrete (exclusive of paving) from SO_2 air pollution in the Boston area. A field survey of 357 sites was conducted, and estimates of the quantities of materials exposed to various SO_2 concentrations in the entire area were developed to serve as a basis for economic damage estimates. Fundamental concepts involved in making materials damage estimates are reviewed, and several papers on the subject are discussed. The contractor is TRC Environmental Consultants, Inc. *EPRI Project Manager: R. E. Wyzga*

Future Natural Gas Supply and Demand Balance

EA-2840 Final Report (RP1981-7); $11.50

This study assesses the future price and availability of natural gas as a boiler fuel in the United States. The analysis focuses on various forecasts of natural gas production and consumption through the year 2000. The contractor is Charles River Associates, Inc. *EPRI Project Manager: K. A. Miller*

Comparison of Solid Wastes From Coal Combustion and Pilot Coal Gasification Plants

EA-2867 Final Report (RP1486-1); $16.00

Solid wastes from conventional coal combustion and from pilot-scale coal gasification plants were compared in terms of selected physical and chemical characteristics. The mineralogy, morphology, particle size, specific conductivity, and hydraulic conductivity of the wastes were determined, and inorganic chemical concentrations were measured in the leachates obtained by batch and column extraction of the wastes. The contractor is Oak Ridge National Laboratory. *EPRI Project Managers: R. M. Perhac and I. P. Murarka*

Inventory of Acid Deposition Research Projects Funded by the Private Sector

EA-2889 Final Report (RP1910-3); $28.00

To help ensure the carefully planned use of technical and financial resources and avoid duplication of research, a survey of acid deposition projects funded by the private sector during 1980–1982 was undertaken. This report presents the information obtained. Projects funded at less than $5000 are not included. The contractor is General Research Corp. *EPRI Project Managers: R. W. Brocksen and R. K. Kawaratani*

Proceedings: EPRI Cogeneration Seminar

EA/EM-2893 Proceedings (RP1050-6); $38.50

This report contains the proceedings of an EPRI-sponsored seminar on cogeneration held in July 1982 in Berkeley, California. The objective of the seminar was to provide information to utilities on the DEUS, COPE, COGEN2, IPGFM, and TEAM-UP models and their applications. The results of a number of application case studies for specific utilities were presented. The contractor is Synergic Resources Corp. *EPRI Project Managers: L. J. Williams and S. D. Hu*

ENERGY MANAGEMENT AND UTILIZATION

Evaluation of Superconducting Magnetic Energy Storage Systems

EM-2861 Final Report (RP1832-2); $11.50

As part of efforts to assess the technical and economic viability of superconducting magnetic energy storage (SMES), a study examined the economic value of SMES from the electric utilities' perspective. Economic values were estimated for three different cases. The contractor is Energy Management Associates, Inc. *EPRI Project Manager: T. S. Yau*

Assessment of European District Heating Technology

EM-2864 Interim Report (RP1276-5); $13.00

This report presents a systematic evaluation of state-of-the-art technologies for turbines, piping, customer connections, and thermal storage in European district heating systems. The technologies are assessed in terms of their potential application to district heating systems implemented by U.S. electric utilities. The contractor is Burns and Roe, Inc. *EPRI Project Manager: S. D. Hu*

Potential for Cogeneration in Distillation

EM-2886 Final Report (RP1276-10); $14.50

A preliminary study assessing the cogeneration potential in U.S. distillation industries—chemical plants and oil refineries—is summarized. The study is based on a literature review and interviews with knowledgeable representatives of industry, architect-engineering firms, and utilities. Possible problems and utility concerns regarding cogeneration in distillation are identified. The contractor is Merix Corp. *EPRI Project Manager: S. D. Hu*

NUCLEAR POWER

BWR Refill-Reflood Program Constitutive Correlations for Shear and Heat Transfer for TRAC–BWR

NP-1582 Interim Report (RP1377-1); $11.50

This report describes the constitutive correlations for shear and heat transfer in the BWR version of TRAC (transient reactor analysis code), a computer code for best-estimate analysis of the thermal-hydraulic conditions in a reactor system. Basic equations are presented, and interfacial shear and wall friction are discussed. The contractor is General Electric Co. *EPRI Project Manager: Mati Merilo*

Nondestructive Evaluation Program: Progress in 1982

NP-2728-SR Special Report; $34.00

This report presents a comprehensive review of the EPRI Nondestructive Evaluation (NDE) Program, including contractor-supplied progress reports of current projects grouped by plant components. The report also serves as the proceedings for the EPRI NDE information meeting held in Charlotte, North Carolina, in November 1982. *EPRI Project Manager: G. J. Dau*

Full-Scale Turbine Missile Casing Tests

NP-2741 Final Report (RP399-1); $17.50

This report presents the results of two full-scale tests that assessed the impact of turbine disk fragments on simple ring and shell structures representing the internal stator blade ring and the outer housing of an 1800-rpm steam turbine casing. Structural and finite element analysis and data interpretation, estimates of energy during impact, missile displacement and velocity histories, and selected strain gage data are included. The contractor is Sandia National Laboratories. *EPRI Project Manager: G. E. Sliter*

Calibration of Instrumented Steam Separators to Determine Quality and Flow Distribution in an Operating Steam Generator

NP-2805 Final Report (RPS139-1); $22.00

This study examined the feasibility of instrumenting steam separators on a steam generator as two-phase flowmeters to measure flow distributions and steam quality near the separator deck plate. Instrumented prototypical separators were tested in a laboratory under steam generator conditions, and test data correlations were developed. The usefulness of such data in the qualification of thermal-hydraulic computer codes was addressed. The contractor is Combustion Engineering, Inc. *EPRI Project Manager: C. L. Williams*

Monitoring Techniques for pH, Hydrogen, and Redox Potential in Nuclear Reactor Circuits

NP-2806 Interim Report (RP1168-1); $11.50

This report describes the development and testing of monitoring instruments to measure the level of corrosivity of high-temperature water in steam power systems. These instruments were developed: a pressure-balanced, external reference electrode for measuring pH and redox potential; a platinum redox-potential probe; a palladium probe for monitoring dissolved hydrogen gas; and a pH probe based on palladium. The contractor is SRI International. *EPRI Project Manager: T. O. Passell*

Methods for the Nondestructive Assay of Spent-Fuel Assemblies

NP-2812 Final Report (RP1578-1); $10.00

As part of a program to develop technology to support spent-fuel storage concepts, the use of nondestructive assay techniques to determine the burnup and residual fissile content of irradiated nuclear fuel was assessed. These methods were examined: burnup measurement by neutron emission, residual fissile measurement by multiplication change with boron displacement, and residual fissile measurement by neutron-source multiplication. The contractor is National Nuclear Corp. *EPRI Project Manager: R. W. Lambert*

Evaluation of RETRAN-02 Capabilities for Small-Break LOCA Analysis

NP-2816 Final Report (RP1320-3); $10.00

The RETRAN-02 MOD2 computer program was used to analyze an experiment on a two-loop test apparatus that simulated a BWR small-break loss-of-coolant accident. Code predictions were compared with test data for pressure, mass flow, fluid density, fluid temperature, and mixture level. The contractor is EDS Nuclear, Inc. *EPRI Project Manager: Lance Agee*

Steam Generator Support Plate Radiographic Evaluation System

NP-2823 Final Report (RPS105-1); $11.50

This report discusses a radiographic technique developed to detect cracks in the ligaments between tube holes and flow holes in drilled steam generator support plants. The equipment was constructed to enable the inspection of support plates with either a triangular-pitched tube pattern (Combustion Engineering design) or a square-pitched tube pattern (Westinghouse design). The contractor is Combustion Engineering, Inc. *EPRI Project Manager: S. T. Oldberg*

Review and Application of the TRAC–PD2 Computer Code

NP-2826 Interim Report (RP1725-1); $14.50

This report presents a study of the TRAC–P1A and TRAC–PD2 computer codes. It includes an analysis of the numerical selection techniques used in the codes, a review of the constitutive relations used in the thermal-hydraulic models, and a comparison of code results with experimental data from various reflood and small-break tests. The TRAC–PD2 code is emphasized. The contractor is Jaycor. *EPRI Project Manager: P. G. Bailey*

Portable Linear Accelerator Development

NP-2831 Final Report (RP822-6); $13.00

This report describes Minac-3, a miniaturized linear accelerator system. It covers the current equipment capabilities and achievable modifications, applications information for prospective users, and technical information on high-energy radiography that is useful for familiarization and planning. The design basis, development, and applications history of Minac are also summarized. The contractor is Schonberg Radiation Corp. *EPRI Project Manager: M. E. Lapides*

Prototype EMAT System for Inspection of Steam Generator Tubing

NP-2836 Final Report (RPS101-1); $11.50

This report discusses the use of an electromagnetic-acoustic transducer (EMAT) as an inspection probe for steam generator tubing. EMAT principles, system design, and laboratory test results are presented, along with conclusions and recommendations. The contractor is Rockwell International Science Center. *EPRI Project Manager: G. W. DeYoung*

Thermal-Hydraulic Tests of Steam Generator Tube Support Plate Crevices

NP-2838 Final Report (RPS121-1); Vol. 1, $26.50; Vol. 2, $14.50; Vol. 3, $19.00

This report discusses the experimental examination, at prototypical thermal-hydraulic conditions, of dryout inception and pressure drop for four steam generator tube supports. Volume 1 presents an overview of the testing, as well as several appendixes; Volume 2 includes appendixes of detailed results and analyses; and Volume 3 presents an appendix with information on raw data storage and retrieval. The contractor is Combustion Engineering, Inc. *EPRI Project Manager: C. L. Williams*

Results of EDF–Framatome Underclad Crack Detection Methods

NP-2841 Final Report (RP2165-1); $13.00

This report describes the development and verification of techniques for detecting cracks under the clad of reactor pressure vessel nozzles and steam generator tubesheets. The origin of the underclad cracking problem is discussed. The contractors are Electricité de France and Framatome. *EPRI Project Manager: J. R. Quinn*

Postaccident Decontamination of Reactor Primary Systems and Test Loops

NP-2842 Topical Report (RP2012-1); $13.00

This report reviews past decontamination efforts on reactor systems and test loops and relates this information to the decontamination of LWRs, particularly Three Mile Island Unit 2. Postaccident situations involving both fission products and fuel debris are emphasized. The contractor is Battelle, Pacific Northwest Laboratories. *EPRI Project Manager: L. E. Anderson*

Fire Retardant Lubricant

NP-2843 Final Report (RP1843-1); $14.50

This report discusses the feasibility of modifying an existing turbine generator lubrication system to use a phosphate ester lubricating fluid. The effects of the fluid on major system components, including the oil supply system, bearings, and generator hydrogen seal system, are reviewed. Performance and material compatibility impacts are identified, and modifications are recommended where required. Modification cost estimates are presented. The contractor is Westinghouse Electric Corp. *EPRI Project Manager: Joseph Matte III*

ENERGY STUDY CENTER

Resources and Economic Assessment of Centralized and Decentralized Solar Electric Systems

ESC-2881 Final Report (TPS79-713); $16.00

This report compares the resource requirements (water, energy, land, material, and manpower) and production costs of centralized and decentralized electricity generation systems using solar photovoltaic devices. Four centralized and four decentralized scenarios were examined. The analysis shows that mainly for reasons related to energy storage, the centralized systems are cheaper to operate and less resource-intensive than the decentralized systems. The contractor is the International Institute for Applied Systems Analysis. *EPRI Project Manager: O. S. Yu*

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