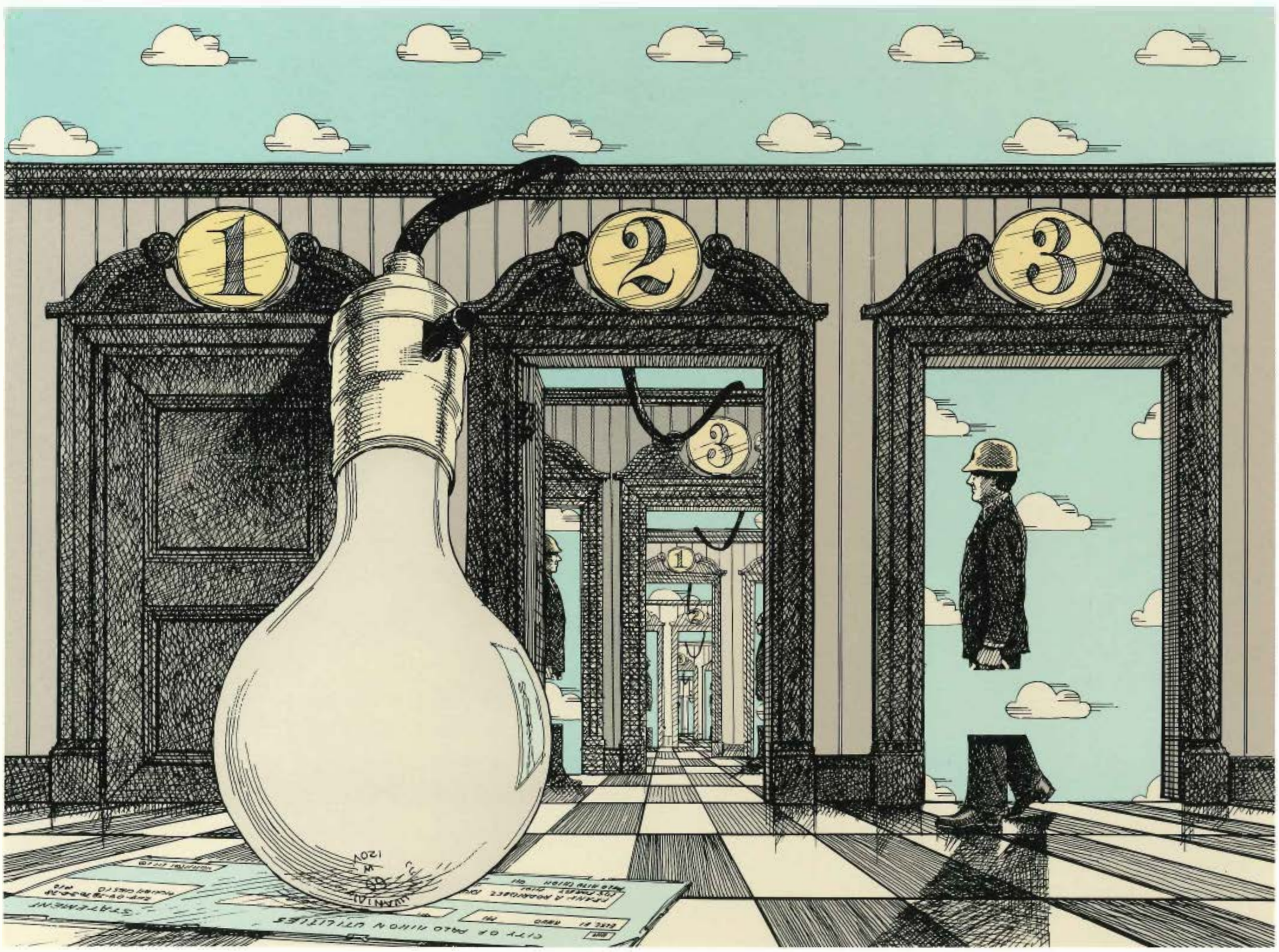
Planning for Uncertainty

ELECTRIC POWER RESEARCH INSTITUTE

EPRI JOURNAL

MAY
1978



EPRI JOURNAL is published by the
Electric Power Research Institute.

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

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Cover: Given a range of demand futures that will vary when seen from the vantage point of each succeeding year, how can a utility today pick the planning reserve margin that will prove to be the most economical when the last door opens?

EPRI JOURNAL

Volume 3, Number 4 May 1978

Editorial

2 **How Much Reserve Margin Is Enough?**

Features

6 **Planning for Uncertainty**
Larger reserve margins appear to minimize overall electricity costs in an uncertain demand future.

12 **EPRI Instruments Reach Commercial Market**
Instruments that verify response time of pressure and temperature gages are now available off the shelf.

14 **Energy, Economic Growth, and Human Welfare**
A respected energy economist examines the relationships between energy, economic growth, and human well-being.

19 **Market Potential for New Coal Technologies**
Generation-expansion analyses on six utility models substantiate R&D priorities for 12 options.

27 **Ellis T. Cox: Pragmatist With a Public Conscience**
The new chairman of EPRI's Research Advisory Committee puts fuel technologies at the top of his list.

Departments

4 **Authors and Articles**
31 **At the Institute**
33 **Project Highlights**
36 **Washington Report**

Technical Review

R&D STATUS REPORTS
38 **Fossil Fuel and Advanced Systems Division**
43 **Nuclear Power Division**
49 **Electrical Systems Division**
55 **Energy Analysis and Environment Division**

58 **New Technical Reports**

How Much Reserve Margin Is Enough?

In a recent editorial, William C. Hayes of *Electrical World* asked, "How much system reliability can you afford?" Because of the tremendous pressure on regulators to keep electric rates from rising, Hayes noted, utilities' construction programs are being based more on financial considerations than on system reliability requirements. He suggested that utilities are at a crossroads: either finance and build new plants at the expense of stockholders or reduce construction at the expense of service reliability. The editor concluded that the "real costs of reduced reliability must be forcefully presented to the regulators." In addition, he strongly urged that consumers be made aware of the true costs of reduced system reliability. (Even without stockholders, of course, publicly owned utilities face a similar conflict in fiscal and operating decisions.)

Utility executives and regulators have always had to grapple with the problem of balancing reliability criteria against the goal of minimizing the consumer's price for electric service. This balancing has taken place with forecasts of electricity demand becoming more and more uncertain. Recently, as explained in this month's lead article, "Planning for Uncertainty," utility planners, EPRI staff, and a consulting firm have developed a novel analytic framework for examining the problem. Indeed, the "over and under capacity" model discussed in the article makes explicit Hayes's concern that there is a direct cost to consumers if system reliability is reduced. It is not just the delivered—and billed—cost of electricity that planners and regulators must examine, but the costs to consumers and society of outages as well. Total costs must be calculated.

Critics of the industry label some reserve margins as "excessive" and point at "unused" capacity as blatant examples of "gold-plating" in the guise of reliability. Regulators generally recognize such arguments as nonsense, but they remain concerned that there might be some "fat" in reserve capacity. However, when extremely cold weather dealt New York, Ohio, and other states a cruel blow during the winter of 1976–77, reserve capacity was strained to take up the energy burden caused by subfreezing temperatures and natural gas curtailments. Similarly, during the earlier oil embargo, "fuel-by-wire" was shipped to the East Coast as utilities along the Mississippi River and elsewhere shared generation capacity, by displacement, with customers along the Atlantic seaboard.

Just this past winter, coal stockpiles shrank during the long strike. Layoffs loomed in several industrial centers, and reserve generating capacity—much of it nuclear—in neighboring states was pushed to nameplate ratings around the clock. There was little criticism, if any, of the utilities having excess reserve margins. In fact, David Bardin, head of DOE's Economic Regulatory Administration, said that he would "rather have too much reserve than too little." And referring to the problems caused by the strike, Bardin added that he appreciated "every bit of (capacity) redundancy" that was available.

Outage or chronic shortage costs must not be ignored. For example, during the coal strike Chase Econometrics estimated that in the industrialized states, a 10% curtailment of electricity would idle about 20% of the labor force. The effect on the economy of a 30% power cutback in the states hardest hit by the strike was analyzed by Data Resources, Inc. If such a reduction became necessary, DRI estimated, industrial output losses alone would total $2 billion a month, and more than half a million jobs would be lost.

Still, how much planning reserve margin is enough for a utility? EPRI's "over and under" model doesn't have all the answers. But, it certainly allowed four utilities that helped develop the model to probe the question deeply and explicitly. This type of analysis, when presented to regulators, can make sense out of a complex problem. It is a credible probing of a contended issue—the expected rate of growth in electricity demand. Furthermore, because several assumptions can be varied to accommodate different subjective views, the model helps to determine if the differences of opinion are crucial to the decision on how much is enough.

Many *EPRI Journal* readers are familiar with the Federal Power Act and its Section 202, which directed the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy. These measures and facilities have served the nation in several recent crises to ensure "an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources." Nevertheless, utilities must build new plants to meet increasing U.S. energy needs. The "over and under" model, in a limited but practical way, offers decision makers some help in reconciling the utility industry's dual mandates: to provide reliable service and to conserve natural resources, both at the lowest possible *total* cost to consumers.

Robert G. Uhler

Robert G. Uhler, Director
Energy Analysis Department

Authors and Articles

As we look ahead, we need to know what the size of our market will be—or failing that, what size utility systems to build so as to maintain reliability at least cost in whatever market eventually materializes. Uncertainty is thus a matter that we seek to accommodate in the most efficient, least costly way. "Planning for Uncertainty" (page 6) develops this idea in terms of utility planning reserve margins and an EPRI modeling study that correlates demand probabilities and the cost components of various generation expansion alternatives.

The EPRI study is headed by Jerry Karaganis, a mathematician and member of the Systems Program research staff for the Energy Analysis and Environment Division. Margaret Laliberte, writing for the *Journal,* joined Karaganis and his colleagues in a number of workshops and discussions to gain understanding of the problem-solving environment in which they work. For Karaganis, the study builds logically on six years in energy analysis and modeling, begun at the U.S. Geological Survey in 1972 and continued at the Department of the Interior before he joined EPRI in July 1974 to specialize in utility studies.

Karaganis is a 1966 mathematics graduate from the University of Buffalo. He went on to earn an MS at Western Michigan University in 1968 and has since completed all the course requirements for a PhD at American University.

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Uncertainty is a fact of life in the performance of utility hardware, a circumstance where R&D can lead to the development of more efficient, less costly equipment and procedures. A small, specialized example is described by John Kenton, the *Journal's* nuclear power editor, in "EPRI Instruments Reach Commercial Market" (page 12). The device discussed is for testing the response time of temperature and pressure sensors. This is an EPRI first: instruments conceived, developed, and licensed for manufacture by EPRI, all under the guidance of David Cain, a test instrumentation project engineer in the Safety and Analysis Department, Nuclear Power Division.

Cain came to EPRI in August 1974 after three years as a plant operations engineer at the Naval Reactor Test Facilities in Idaho Falls. He is a 1966 University of California graduate in electrical engineering, with MS and PhD degrees from the University of Washington.

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We are glad to welcome Sam Schurr as a *Journal* author this month. Formerly director of EPRI's Energy Analysis and Environment Division, he is again with Resources for the Future, Inc.—his career for more than 20 years—now as codirector of RFF's Center for Energy Policy Research.

In "Energy, Economic Growth, and Human Welfare" (page 14), Schurr acknowledges the controversy that has arisen over the proposition of causal links among these three subjects. He traces the history, separates ideology from fact, and points to what we can learn from the record. In Schurr's view, energy supply, traditionally seen as the constraint breaker, may itself become a constraint on growth. He poses the need for national policies "to surmount supply and environmental constraints."

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It's unlikely that all the advanced coal technologies under development today will be used on utility systems. But which ones will, under what circumstances, and to what extent? Some kind of educated guess at the answers is needed in setting and revising R&D priorities.

Dwain Spencer and Oliver Gildersleeve tell how EPRI goes about making that educated guess by measuring the "Market Potential for New Coal Technologies" (page 19). Their work takes the form of progressively refined cost projections, which are inserted into generation expansion studies of several representative utility models.

Spencer today heads the Advanced Fossil Power Systems Department in EPRI's Fossil Fuel and Advanced Systems Division. But his interests are wide in range. He organized the Solar Program when he came to the Institute in April 1974. And during the 16 previous years with the Jet Propulsion Laboratory of the California Institute of Technology, he not only worked on a variety of space system designs and studies but ultimately took management responsibility for the application of space technology in several professional and industrial fields.

Oliver Gildersleeve came to EPRI in August 1976 from Philadelphia Electric Co., where he specialized in energy conversion research during much of his 11-year tenure. He is a mechanical engineering graduate of the University of Pennsylvania, where he later earned an MS in systems engineering. Gildersleeve is a project manager for utility systems analysis in the Program Integration and Evaluation office of the Fossil Fuel and Advanced Systems Division.

Much of the wisdom with which EPRI allocates its resources resides in the Institute's senior technical advisory group. The new chairman of the Research Advisory Committee is "Ellis T. Cox: Pragmatist With a Public Conscience" (page 27). Cox is also executive vice president and chief operating officer of Potomac Electric Power Co., and his professional views in both roles were discussed when he was interviewed by Marie Newman of EPRI's Washington office.


Karaganis


Spencer


Cain


Gildersleeve


Schurr

PLANNING FOR UNCERTAINTY

Reserve generating capacity costs money, and so does a capacity shortfall. But as future electricity demand becomes harder to forecast, larger planning reserve margins may be more economical in overall cost to consumers.

When I was put in charge of load forecasting at Commonwealth Edison a number of years ago, some people considered it the easiest job in the company," reminisces René Malès, director of EPRI's Energy Analysis and Environment Division. "'Growth is so regular in this industry,' the chairman told me, 'in a 10-year period you can't be wrong by more than one year—either too early or too late. We can take care of that in the construction department. So, instead of doing a complex analysis, you could just as well take a ruler and draw a line and be right, plus or minus a year.'"

In those days steady demand growth and short construction lead times meant that the various departments in a utility could depend on a load forecast without concern that it would be changed. The load forecaster gave his projections to the operations planner, whose time was mainly spent on immediate capacity additions rather than on system plans for a future 10 or 15 years down the road. Fuel supply and sound financing were regarded as assured "givens" by planners, and the environmental impacts of electric power production had not yet become a social issue.

A catalog of uncertainty

Today, load forecasting is no longer easy, and the job of planning a utility's capacity expansion has become a task requiring complex coordination of many departments. Systems planning is now distinct from operations planning; fuel supply forecasting is a crucial and uncertain factor; the financing of multimillion-dollar power plants with lead times up to 12 years—or even more—is a major undertaking; and environmental concerns have become a highly sensitive issue.

The largest single difficulty in making wise capacity expansion decisions is that the future demand for electricity is much more uncertain. No one knows what effect higher fuel prices and changes in rate design will have on that demand. Technological changes—industrial cogeneration, heat pumps, solar heating and cooling systems—will have their influence, but their form and extent are difficult to foresee. Government decisions like California's tax incentive legislation to encourage homeowners to install solar systems or the proposed federal tax incentive for conservation may also alter demand—though it is still uncertain if or when the federal legislation will come about. Further, no one is sure what level of economic growth the country will realize over the next 10–15 years.

No one knows what combined effect all these factors will have on the kilowatts of plant capacity that must be planned. The forecaster's computer can juggle figures forever, but it can't create certainty about future demand when none exists.

A second difficulty in capacity planning is inherent in today's technologies for generating electricity. Widely varying lead times control the installation of power plants, from 2 years for gas turbine systems to 12 years or more for nuclear facilities. Bringing these plants on-line involves a sequence of decisions over several years, from the initial commitment to study and design a plant, through licensing and construction, to startup. The need to coordinate these sequential decisions with changing forecasts of future demand considerably complicates the capacity expansion process.

A divergence of viewpoints

Even if demand were certain and decisions could be closely coordinated, a tough issue would still remain. Energy planning decisions involve many parties outside the utility itself, all with their own interests and viewpoints, and no agreement exists about what the ultimate goals should be or how one set of values can be traded off against a different set. On the one hand, a large utility customer—a computer center—wants to be sure its service is totally reliable because just a few seconds of interrupted service could erase its data base. On the other hand, a public interest group may question the value of capacity expansion, especially if it involves construction of a nuclear plant. Or a state commission may want to control expansion by limiting the number of sites it will approve for utility use.

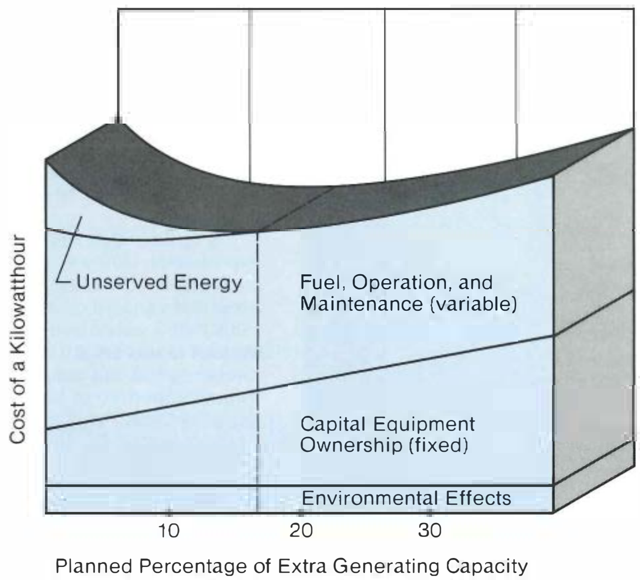
The implications of these various, often conflicting, views are usually measured on different scales, and the lack of a common language has made the resolution of such differences a frustrating problem to everyone concerned.

In view of all these factors, the position of a utility planner today is akin to that of a traveler facing a fog-shrouded highway. Will there be a clear, straight stretch ahead, without curves or obstacles? More likely there will be forks in the road, alternative routes among which to choose. And what about the vehicle—is it appropriate for the route ahead, or will it slow him down? Will there be the chance to exchange it for equipment better matched to the terrain actually encountered?

Call for a new question

Similarly, the planning process has entered an era of new complexity, where down-the-road visibility is obscure. Up to now, utility capacity expansion plans have been based on the expedient question, What is the future demand for

The Cost of Future Reserve Capacity

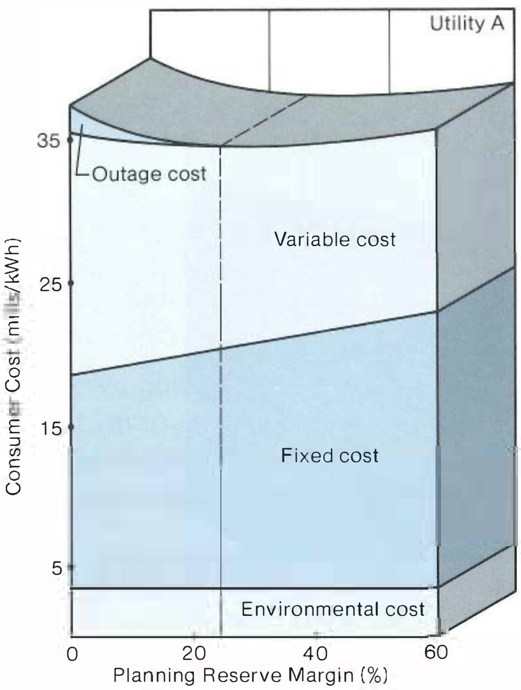


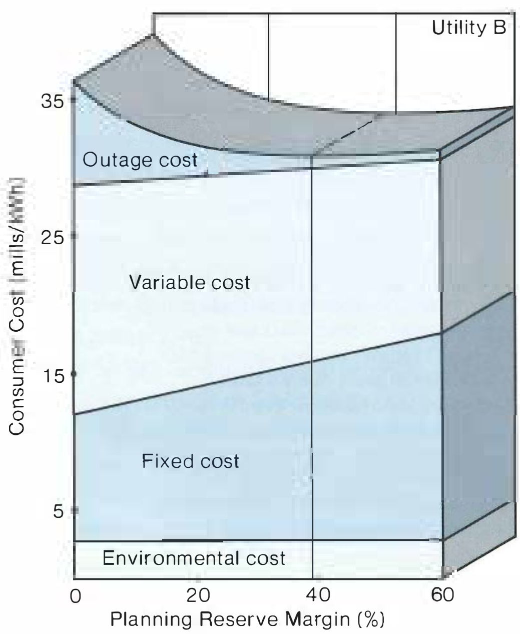
Every electric utility has generating units standing in reserve (over and above nominal system requirements) to deal with extraordinary peak loads and to substitute for units that break down or must be shut down for periodic overhaul. All units on a system must be planned well in advance, requiring orderly commitments of money and time for studies, designs, licenses, and construction.

When future demand is uncertain, the amount of future reserve margin to have in the various stages of commitment and investment is a complex planning question. But there are foreseeable cost penalties that will result from arriving at a given future date with either too much or too little reserve.

This U-shaped curve represents the output of a method devised by EPRI to compare the costs of different planning reserve margins on a utility system when probabilities are assigned to various future values of system capacity requirement. The low point marks the future margin of least overall cost as it is seen today. Equally important are the slopes of the curve away from the low point; these indicate that electricity cost is apt to increase more sharply with a lower reserve margin than with a higher margin. The costs of unserved energy—incurred by consumers during a blackout, for example—are not on electric bills but the assigned level of these outage costs is crucial to the analytic method.

The Optimal Planning Reserve Margin





Different circumstances among individual utilities—notably the mix of planned types of units and the cost assumptions for outages (unserved energy)—influence the shape of the U-shaped curve and the optimal reserve margin that results, which is measured as the levelized consumer cost of electricity required to achieve that margin.

The optimal 24% margin of hypothetical Utility A, for example, is controlled by the fixed and variable costs of units that it would add to attain various reserve margins. This circumstance can result from a heavy proportion of oil-fired capacity today. Replacing some of it over time with coal-fired or nuclear units will yield lower variable costs (fuel and O&M). Outage costs are a small increment in this example because Utility A's hydroelectric capacity is substantial and is thus a reliable, flexible, and economical source of peak demand power.

Utility B, on the other hand, has a large proportion of efficient baseload capacity that results in low variable costs. Capacity additions can only increase its fixed costs, even though variable costs taper a bit. Furthermore, on this system of large units, even one forced outage implies more unserved energy and sharply greater outage costs if the future reserve margin falls short. This drives Utility B's optimal planning reserve margin to nearly 40%.

electricity expected to be? To answer that question, elaborate econometric models have been developed that extrapolate the future from the past and present. Aware of uncertainty in the future, planners usually produce high-, medium-, and low-demand scenarios and then choose a compromise figure that reflects an implicit hedging of their bets. Although some flexibility results from this approach, the information used to arrive at expansion decisions and determine the desired flexibility gets buried within the total data, and it isn't possible to track the reasoning involved in the decision making.

Recently a small group of analysts challenged this traditional approach. In 1976 the California Energy Resources, Conservation, and Development Commission studied the effect of demand uncertainty on optimal expansion rates. The results of that research were unexpected. With the addition of uncertainty, it was found that the most beneficial rate of capacity expansion (in terms of minimizing possible additional costs to consumers) was significantly greater than the expansion rate when demand was certain. The implication was that demand uncertainty is indeed important in utility planning.

In view of this finding, it appears that a new question for planners is in order. Rather than asking what demand will be, a better question is, What is the best way to plan capacity expansion based on demand uncertainty? In other words, knowing that the road ahead is hidden by fog, the best way to prepare for the junctions and forks that may lie ahead is to make uncertainty an explicit part of the decision-making process.

Responding to the question

EPRI's Energy Analysis and Environment Division has recently developed a planning model to deal with utility decision making against many futures. Starting with methodology that they helped to develop at SRI International for the California study, analysts of Decision Focus, Inc. (DFI) worked closely with the planning staffs of four participating utilities (Long Island Lighting Co., Pacific Gas and Electric Co., Tennessee Valley Authority, and Wisconsin Electric Power Co.) to ensure that the new approach is relevant.

"We were interested in really locking minds, using the practical methodology of the utility planners and the decision analysis expertise of DFI to synthesize something that can work in the real world," says Jerry Karaganis, the Systems Program project manager who directed the study. "The utility planners helped develop the model itself, and the net result was a significant advance over the approach used in the California study."

EPRI's model makes demand uncertainty an explicit factor in capacity expansion planning and uses it to build a flexible electric power system—that is, one for which a utility can make cost-effective decisions about capacity additions as demand actually materializes. The results of EPRI's analysis suggest that such a flexible system should actually cost consumers less money than would a conventionally optimized planning procedure.

Four cost components

As a basis for its analytic and modeling approach, EPRI suggests that the costs associated with producing electricity and providing service be divided into four categories: fixed, variable, outage, and environmental costs—all of which the consumer ultimately pays, directly or indirectly. Fixed costs are represented as carrying charges on capital investments. Variable costs are those of fuel, of labor and parts associated with maintenance, and of meeting demand by turning to interties, interruptible customers, and voltage reductions.

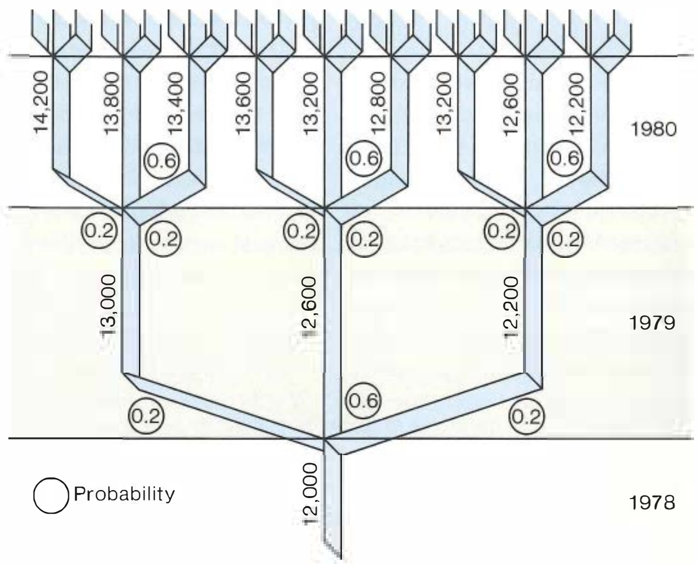
Customers not only pay for electric power, they pay for not receiving service as well. Thus, the cost of outages, or unserved energy, is a crucial component of this approach. Analysts are only beginning to devise methods of attaching dollar values to the costs associated with interruption of utility service. It is clear, though, that these will always be specific to each utility and that they will change over time as the utility's service area changes and matures.

Basically at issue is how much the utility's customers value reliable electric power. If, because of service interruptions, customers install their own emergency generators, they incur real, calculable costs above those that appear on their utility bills. Or instead, if perishable merchandise spoils or customers lose business, they also incur real costs. Outage costs, then, are a societal cost that should be included when a utility attempts to plan a least-cost system for its customers.

All utility planners today place a value on outages for their planning purposes. EPRI's contribution to the issue lies in the way in which it makes outage costs explicit in the decision-making process. It enables utility personnel to run a sensitivity analysis to reveal if their planning decisions would change if they placed a different value on outage costs.

Finally, environmental costs are as-

A Picture of Probabilities



The uncertainty of system capacity growth requirements is represented by this probability tree of alternatives for the next two years. Extended and branched throughout a planning period, it produces a range of future capacities and reserve margins. With recognition of generation types, costs, and lead times, that range can be reduced to a present-day estimate of the future mix that must be committed to successive planning, licensing, and construction stages during the intervening years. Revised demand forecasts and probabilities can be incorporated annually (and the plan extended another year) so as to accelerate or slip the scheduling of future units.

sociated with electric power generation. On the one hand, an undersized, older utility system contains generating units that are being pushed past their optimal efficiency. As a result environmental controls are not as effective as planned, and the company may need to seek variances or pay fines for airborne particulates that pollute the air. On the other hand, a system with planned overcapacity can schedule proper maintenance and run its units efficiently, so that it tends to be environmentally sound.

In this regard, it is important to remember that an oversized system does not necessarily produce more energy than an undersized system, and where energy production is the same, the total amount of pollutants released would actually be less with the oversized system.

There is still another trade-off to consider, since planned overcapacity ties up land. This does not mean that power plants are sitting around unused. Rather, sites may have been approved and plants licensed that are being held in that status, or "slipped," until demand or other issues are resolved and the plants are either built or cancelled. In EPRI's study, a balanced trade-off in environmental costs between under- and oversized systems was assumed, according to the present state of knowledge about the issues. In other words, environmental costs were held constant.

Focus on reserve

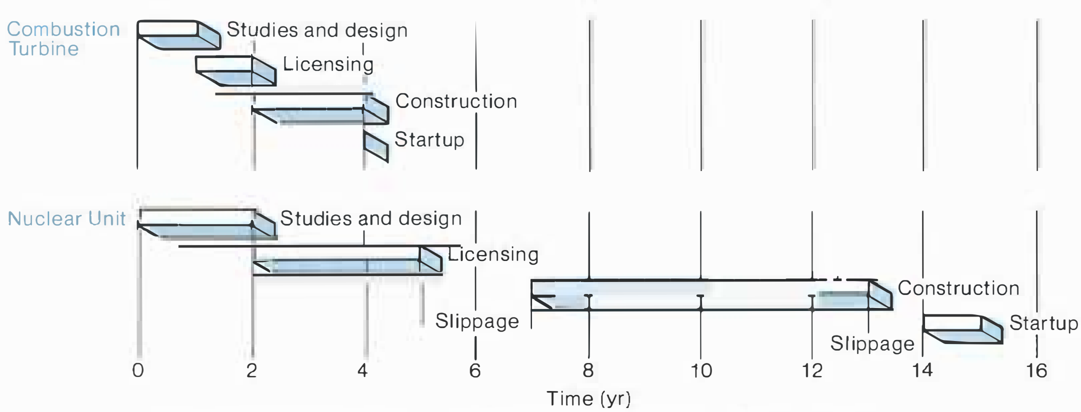
For purposes of this analysis, the planning reserve margin was made the decision variable. This is a measure of reliability that is easier to conceptualize than is the traditional utility measure, loss-of-load probability, which is expressed in terms of the number of outage days in a certain number of years.

When a utility feeds data relating to the four costs (fixed, variable, outage, and environmental) into the capacity expansion model, the model attempts to represent electric capacity additions for that utility, guided, of course, by several givens: a mix of generation technologies, a planning reserve margin, and a demand probability tree. The tree simulates the multiple futures assumed for electricity demand. Consisting of several branches and nodes, it represents the fact that in each particular time period demand may turn out to be high, medium, or low. The branching pathways capture the fact that the expectation of demand growth becomes increasingly uncertain as one looks further into the future. The uncertainty associated with each pathway can be handled probabilistically. As a result, each branch at each node is labeled with a certain probability of occurrence.

Simulating generation expansion

As the model moves through the planning period, it makes decisions on how the system should expand, based on how demand uncertainty gradually resolves, what consequent future demand becomes evident, what initial capacity was available, what generation mix is desired, and what lead times control various new capacity additions. The model simulates the sequential decisions that utilities must make to carry planned additions from initial studies through licensing to actual construction and startup. Procedures allowing plants to slip at any stage of the process are an important way that utilities deal with demand that changes after an initial commitment to a capacity addition. In this way the fixed costs of an expansion plan can be computed.

The Timing of Capacity Additions



Each type of generation unit—a combustion turbine for peak demand service or a nuclear-powered baseload unit—has its own time scale for each stage of development until it comes on-line. (These increments vary from one utility to another.) If the demand forecast falls off, the unit can be slipped; if demand picks up, it can be replaced in the plan by a different type of unit having a shorter lead time (with a consequent change in the cost picture).

The model simulates electricity production and computes the variable costs for each year of the planning period along each pathway of the probability tree. When these fixed and variable costs are added to the calculated outage and environmental costs, the result is a stream of total costs for each pathway. These costs are then discounted back to 1978 dollars, a procedure that determines their present value to consumers. Next, the model levelizes each pathway's cost to consumers over the planning period. Finally, using the probability associated with each pathway, the model computes the expected cost to consumers of the expansion plan at a given planning reserve margin.

Varying the reserve margin

When the model runs several times, each time with a different planning reserve margin, curves associated with the four cost categories are produced.

As would be expected, fixed costs increase steadily as the planning reserve margin increases, since more capacity is being installed. On the other hand, variable costs tend to decrease with added capacity since utilities can replace older technologies or oil-fired plants that have become expensive to operate with a new and more economical mix. Outage costs decrease with increasing reserve margin because a utility with greater reserve can meet more of the demand for power. Environmental costs are shown by a horizontal line indicating that a constant value is assumed. If actual figures are available to a utility, they could be used in sensitivity analyses in the same way outage costs are.

A significant curve

The results of this new type of analysis are significant. When the fixed, variable, and outage costs are fitted together, a curve emerges whose shape is not only U-shaped but also asymmetrical. The bottom of the curve locates the least-cost planning reserve margin when demand is uncertain. The cost to consumers of electric power is minimized when capacity expansion is pegged at that reserve margin.

The curve's asymmetry shows that the additional costs associated with planning at a lower reserve margin (and consequently sometimes ending up with undercapacity) are significantly larger than the costs associated with planning at a higher reserve margin and its potential for overcapacity. In other words, if a utility maintains a low planning reserve margin and demand turns out to be consistently higher over time than was anticipated, the utility must attempt to meet that demand by installing modes of generation with short lead times (which tend to use expensive fuel), drawing on interties, interrupting service, or even incurring outages. The costs to consumers of these eventualities are greater than the costs of supporting a higher planning reserve margin, even though it entails the commitment to studies, licensing, or construction of generating units not actually needed if demand turns out to be less than expected.

Information sensitivity

The U-shaped curve actually represents a best-guess case and is really only the starting point in a debate over a utility's capacity expansion plans. Its value lies in pinpointing the critical information for a specific utility. By using sensitivity analyses, various views can be accommodated to determine how a change in one assumption might affect the utility's expansion planning decisions.

For example, how would the curve look if outage costs double? A sensitivity analysis might indicate that the least-cost planning reserve margin would shift 10 points to the right under those conditions. Or conversely, it might reveal that the particular utility is not sensitive to changes in outage costs. If it relied heavily on one generating technology, however, the analysis might show it to be quite sensitive to an increase in the cost of oil or to a coal strike. In other words, the model is sensitive to the specific information brought to the debate. As a result, the parties involved can determine which arguments are actually pertinent and which ones only cloud the issue.

Karaganis recognizes that the particular model developed for EPRI doesn't provide all the details utilities need for planning purposes. But its concepts of dealing with multiple futures and sequential decision making can be adapted to the more complex planning models that utilities now use.

The Systems Program will develop its new approach by expanding the number of concepts the model can handle, using different utilities' data, accommodating broader demand uncertainty, and reviewing other decision variables.

A framework, not final answers

Results of the California Energy Resources, Conservation, and Development Commission and EPRI studies highlight a crucial finding. Given all the uncertainties in utility capacity planning, it appears that attempts to reduce the costs of electric energy by controlling one or more of the uncertain factors will result in greater costs to consumers. Reduced planning reserve margin, for example, may lead to a power system so imbalanced that it is inefficient and expensive to operate. A better solution, EPRI suggests, would be to allow utilities some planned flexibility so they can react to the market forces of fuel supply and prices, demand for electricity, consumer expectations for reliable service, and so on.

"We're not claiming to have definitive, final answers or to tell utilities how to plan their systems," Karaganis emphasizes. "Our contribution is to offer this framework that allows everyone to pose questions and see which ones really turn out to be relevant. My personal feeling is that the more we can quantify relationships explicitly, the greater our chances are of finding solutions to our problems."

When NRC wanted verification of sensor response times, EPRI developed the instruments to do the job.

EPRI Instruments Reach Commercial Market

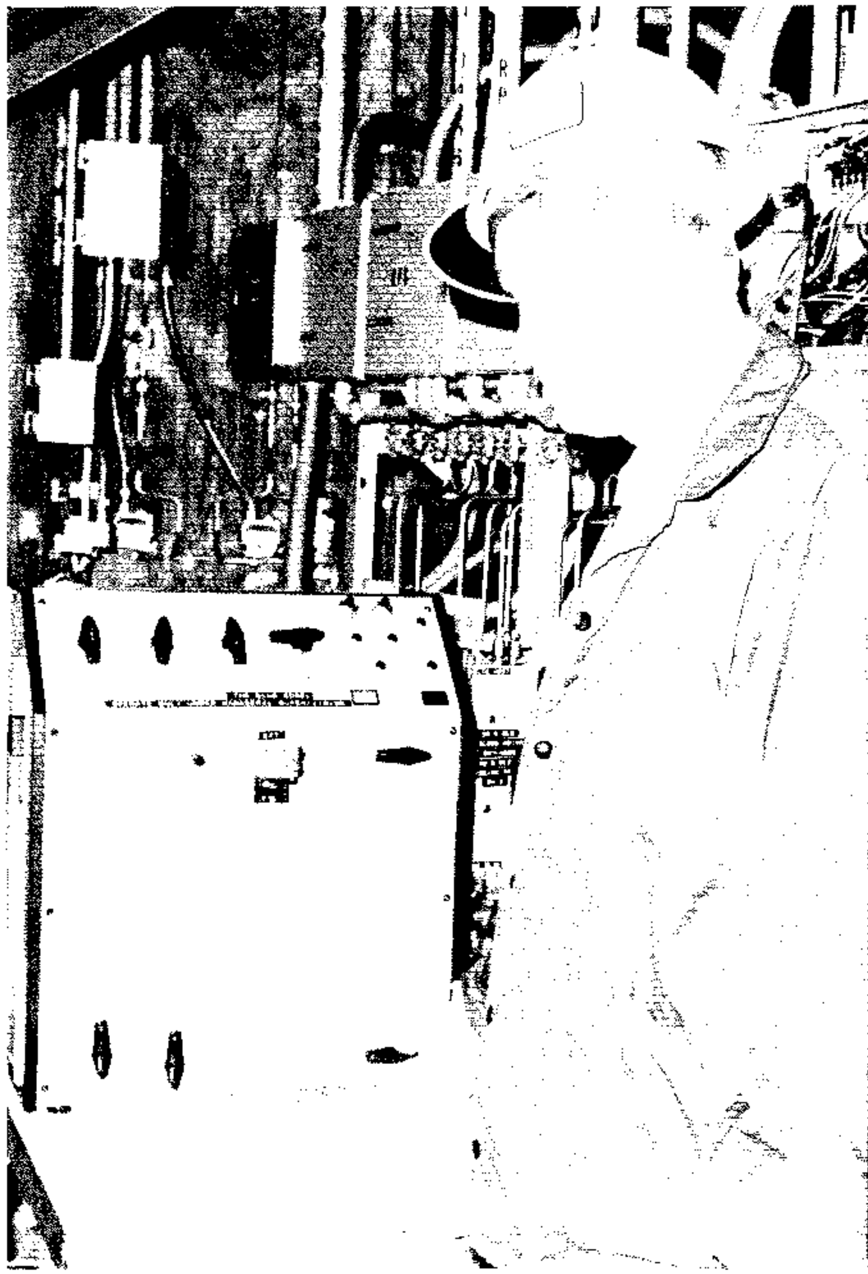
The first EPRI invention to become off-the-shelf hardware is now commercially available. A patent is pending and the device—an instrument to verify the time response of pressure sensors used in power plants—has been licensed for production and marketing. A related device, one to verify the time response of temperature sensors, is also now commercially available.

Some of the research performed at EPRI has useful information as its end product. Other research produces results that may be useful in developing and commercializing future technologies. Yet another kind of research provides technological solutions for current problems. This is the case with the time-response instruments. It is noteworthy that these first EPRI hardware products to become commercial are not the result of chance invention but are the result of work specifically undertaken to solve an existing problem faced by utilities. A problem was identified, a research project was designed and carried out, and from this a new test instrument that gives a needed tool to the utilities was perfected.

The problem

In a light water reactor, as in a fossil-fired boiler, measurement of the temperature and pressure of the primary loop coolant water (or boiler feedwater) is of considerable importance for safety and routine operation. Knowing the exact time period over which a change in temperature or pressure takes place allows the reactor protection system to sense the onset of abnormal transients and to initiate reactor shutdown before design limits are exceeded. To establish this time period with precision, it is necessary to know how long the sensor takes to respond to a change in the parameter being measured.

Pressure sensor response-time set in the Duane Arnold nuclear plant in Iowa.



Utilities operating nuclear plants have been taking credit for sensor response time in plant safety analysis reports to the U.S. Nuclear Regulatory Commission. But about three or four years ago NRC challenged utilities on this, asking them to prove that response times of sensors do not degrade beyond values claimed. In support of this position NRC issued a regulatory guide stating that sensor response time had to be periodically verified.

At that time there was no practical way to do this, at least not in situ (i.e., without removing the sensor for test under laboratory conditions). David Cain, a test instrumentation project engineer in EPRI's Nuclear Safety and Analysis Department, formulated three research projects to solve the multiple technical problems that were involved. The contractors were Nuclear Services Corp. (NSC), the University of Tennessee, and Babcock & Wilcox Co. (B&W).

NSC worked on a hydraulic test instrument for verifying the response time of pressure transducers. Concurrently, the University of Tennessee developed a loop current step response (LCSR) test unit for solving the sensor-versus-time problem for temperature measurements. And B&W began working on an alternative approach—noise analysis—applicable to both temperature and pressure sensors.

The NSC project resulted in the hydraulic response test set being patented by EPRI. A spinoff company, Industrial Design and Engineering Associates (IDEA) is manufacturing the test units under a license from EPRI, and NSC is marketing the units. The LCSR method is not patentable because early work carried out at Oak Ridge National Laboratory is in the public domain. However, another young company, Technology for Energy Corp. (TEC) of Knoxville, Tennessee, plans to market both the hydraulic test set for pressure sensors and the LCSR test set for temperature sensors. TEC is now negotiating a license from EPRI to manufacture the hydraulic test instrument. A third firm, Analysis and Measurement Services, is marketing LCSR test hardware and a full range of temperature sensor response time analysis capabilities.

Pressure sensor timing device

The hydraulic test set is a portable unit that provides a simple, convenient means to test response-time of the pressure-sensing equipment in place. It is a single compact unit containing pressure accumulators, valves, a reference transmitter, and associated electronics, and it is designed to be filled with test fluids and connected to the pressure sensor and peripheral equipment.

It functions by generating controlled, repeatable ramp pressure changes that are sensed simultaneously by the plant pressure transmitter and by the reference transducer within the test unit. The latter acts as a dynamic standard against which the time response of the pressure sensor is evaluated during the course of the test.

Recorded data for a given test can be analyzed rapidly by the technician before the test set-up is disassembled.

The unit weighs 32 kg (70 lb) and is about 56 cm high, 48 cm wide, and 25 cm deep (22 × 19 × 10 in). It can be used to test the pressure sensors in the instrument systems of either nuclear or fossil-fired plants. The unit may be purchased as an off-the-shelf item from NSC.

EPRI is the sole owner of the hydraulic test unit for which a patent is now pending. A licensing and royalty fee structure has been established.

Furthermore, any utility having the shop capability and wishing to do so may construct the instrument from sufficient detailed information provided in EPRI's final report on the project, NP-267, *Sensor Response Time Verification.*

Temperature sensor timing device

The LCSR is designed for testing a standard type of temperature sensor known as a resistance temperature detector (RTD). The LCSR technique involves measuring the RTD temperature response output when its supply current is abruptly increased from its normal value of a few milliamperes to a level of tens of milliamperes. The resulting resistive heating of the RTD filament causes a rise of a few degrees in internal temperature. The RTD's response time may then be determined by observing its response to the current perturbation and using a mathematical transformation to compute the dynamic response.

A typical LCSR test unit is a compact system, consisting of current supply, bridge circuit, control module, and signal conditioning elements. The unit supplies the transient current to the RTD and feeds LCSR data to a recording system. A FORTRAN-based software package is used to compute the RTD time constant from the digitized output.

In-plant testing program

Both hydraulic and LCSR test units have been tested in commercial power plants to demonstrate the validity of these methods for in-plant testing to meet NRC requirements. On the basis of the results of this demonstration program, utilities and product suppliers are submitting this technology to the NRC for approval as a standard test method. Industry standards are being written to incorporate the new response-time testing technology.

LCSR units have been tested in representative PWR units of each of the three domestic PWR manufacturers. Furthermore, the technique has been used in a large West Coast PWR seeking NRC fuel-loading authorization. These plant tests were confirmed by independent laboratory tests.

Noise analysis technique

The B&W project is investigating possible uses of process noise fluctuations to determine sensor response characteristics. The technique has been subjected to in-plant testing, and the results suggest it is effective for qualitative interpretation of data but not yet for quantitative. Investigation of a more powerful noise analysis procedure, time series analysis, is under way in an effort to overcome this limitation.

Energy, Economic Growth, and Human Welfare

by Sam H. Schurr

A respected energy economist examines the relationships between energy and prosperity and calls for policies to achieve energy supply *and* environmental goals.

A couple of propositions widely accepted until recent years are now subject to great controversy. The first asserts that there is a direct and strong connection between economic growth and the growth in human welfare; the second, in a parallel fashion, claims a strong link between energy growth and economic growth.

The controversy that surrounds these propositions is a mixture of ideology, facts, and the interpretations placed on the facts. My purpose here is to try to sort things out—to see where ideological considerations end and facts begin and to determine what we can and cannot learn from the factual record. I will also deal with policy approaches that are appropriate in the light of existing knowledge on these subjects.

Economic growth and human welfare

Let us consider first the proposition that posits a strong connection between economic growth and human welfare. The controversy now surrounding this question appears to be largely a matter of ideology. There are those who point to relatively high levels of per capita income in advanced industrial countries and to a number of social indicators, such as health conditions, access to higher education, upward mobility of the population, labor-saving appliances, and physical mobility, to support their belief that human welfare has increased as a result of economic growth. In direct opposition are those who question the significance of a higher GNP per capita and point to other indicators, such as pollution, crowding, crime, alienation, time lost in commuting, and declining durability of products, which are said to demonstrate a pervasive deterioration in the quality of life.

Unfortunately, there appears to be no objective way of comparing the contradictory sets of criteria that would be acceptable to those holding the opposing viewpoints. In the absence of an acceptable common denominator, the debate is bound to continue without resolution because it is the bases of the value judgments that are in conflict.

A more objective basis of judgment probably can be reached if one asks not about human welfare per se but instead about the conditions of economic growth that are most compatible with minimizing political and social conflict in today's world. In response to this question, I believe it is fair to begin with the observation that those who have less usually want more—a generalization that appears to hold among both people and nations. It is obviously far easier to provide more for everyone by distributing shares of an ever-growing economic pie than by reapportioning the shares of an unchanging one.

Economic growth also appears to be the solution to coping with many specific social and economic conditions urgently in need of attention. In the United States, unacceptably high levels of unemployment and price inflation are a case in point. How is reasonably full employment to be achieved if not through higher rates of growth? And how is full employment without higher inflation to be achieved except through growth that is accompanied by increased productivity? Solutions to a large number of national needs in the United States, such as housing and urban rehabilitation, would be similarly expedited by higher rates of economic growth.

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Worldwide economic growth

The need for faster worldwide growth is equally compelling if conflict is to be reduced within the less-developed countries and between those countries and the industrialized world. To deal with their problems, the less-developed countries have adopted industrialization as a major goal. A declaration issued in 1975 by these countries set a goal for themselves of providing at least 25% of the world's industrial production by the year 2000. Subsequently, in May 1975 the United Nations Conference on Trade and Development (UNCTAD) declared that this goal would mean an 11% annual growth rate in manufacturing output for each of the intervening years. Serious questions can be raised about the feasibility of attaining this target. For our purposes, though, what is important are the aspirations and the need to move toward their satisfaction in the interests of international stability.

It is important to aim for a high economic growth rate in order to deal with potential sources of domestic and international conflict. The debate over whether such growth will finally serve to enhance human welfare probably cannot be resolved because of a clash in value judgments. However, questions concerning the quality of life deserve serious attention in mapping growth strategies in order to guard against the undesirable consequences that social critics have forcefully brought to our attention in connection with past economic growth.

Economic growth and energy consumption

In respect to our second proposition, which asserts a strong connection between economic growth and growth in energy consumption, there is a detailed factual record for the United States and other countries to refer to. However, even with an extensive historical statistical base, serious questions are raised about the interpretation to be placed on the facts, particularly as they apply to the anticipated future circumstances of the United States and other industrialized countries.

First, let me offer a brief summary of what U.S. history says about how economic growth has affected growth in energy consumption. Later I will consider the converse of the relationship—how energy supply has affected economic growth. This aspect is of critical importance, but it is frequently overlooked.

The statistical record tracing the relationship between energy consumption and GNP in the United States is available from the latter part of the nineteenth century to the mid-1970s. When GNP (measured in constant dollars) and Btus of the total consumption of mineral fuels and hydropower are compared, this time span divides into three periods:

- An early period—from the latter half of the nineteenth century to about the second decade of the twentieth century—in which energy consumption grew at a faster rate than GNP
- A middle period—from about the end of World War I to mid-century—in which energy consumption grew at a slower rate than GNP
- The most recent period, in which there have been numerous short-term fluctuations but no persistent secular trend either up or down

The relative stability in energy/GNP ratio during the last period stands in sharp contrast to the two earlier long-term movements. This is the period usually referred to when a close relationship between GNP and energy consumption is said to be displayed in the historical record.

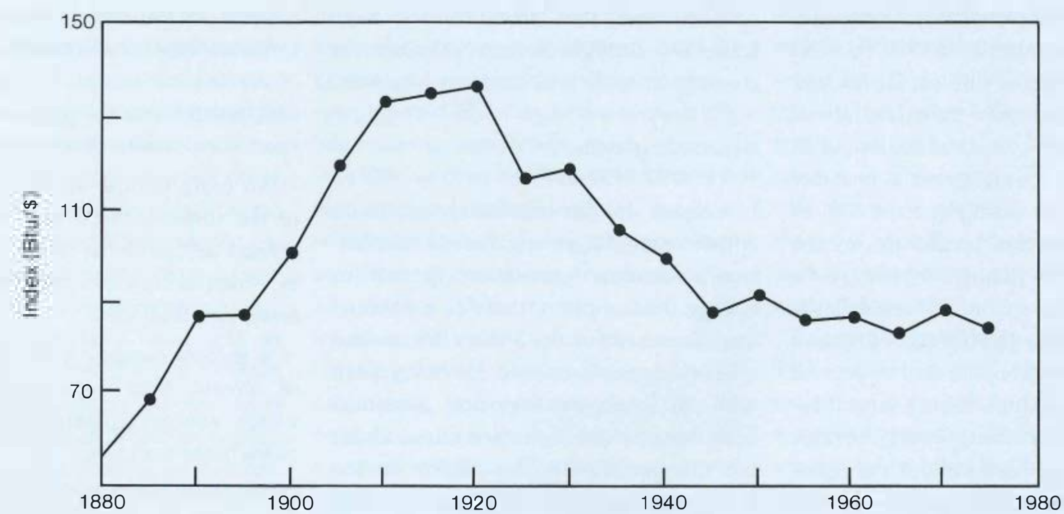
Two major points should be emphasized. The first is that despite the close relationship between GNP and energy consumption since World War II, the long historical record does not support the view that these factors have grown at essentially the same rate. Not only did they not grow at the same rate, but their comparative rates show divergence in different directions, depending on the period of U.S. economic history being covered.

The second major point is that the changes over time in the relationship between energy and GNP have not been drastic. Even over the several decades when energy consumption declined persistently relative to GNP, the reduction in the ratio came to no more than about one-third. These were turbulent years for energy supply and use; there were fundamental changes in the composition of U.S. energy output, including a phenomenal rise in the importance of energy in the form of electricity and liquids as opposed to the earlier heavy domination of coal. And there were sharp increases in thermal efficiency in such major areas of energy use as railroad transportation, electric power generation, and space heating. Yet the one-third decline in the ratio between energy consumption and GNP, though significant, was far less drastic than some of the forecasts now being made for the next 25–35 years.

Thus, although the recent historical record points to a strong relationship between economic growth and the demands placed upon energy inputs, earlier periods show substantial departures from parallelism in the movements of these two aggregate measures. The profound changes in energy supply and use technology that occurred during the single sustained period of decline in energy consumption relative to GNP (1920–1945) place a strong burden of proof on forecasts that project a substantial decoupling of energy consumption and GNP in the future. To be credible, such forecasts should be accompanied by specifications of those changes in energy production and utilization technology that are supposed to produce such a decoupling and plausible evidence of their technical and economic feasibility.

Assessing the future

In drawing such a cautious conclusion, I do not mean to deny that there are numerous opportunities to utilize energy more efficiently without serious (if any) impairment of the services that energy yields. Examples that come readily to mind include smaller and more efficient



This index of United States energy consumption per unit of gross national product (GNP) between 1880 and 1975 reveals three distinct periods: 1880–1920, when energy consumption rate grew faster than GNP; 1920–1945, during which growth in energy consumption rate was slower than growth in GNP; and 1945–1975, when there were several short-term fluctuations with no persistent trend up or down, displaying a close relationship between energy consumption and GNP. Source: Data for the 1880–1950 period are from *Energy in the American Economy, 1850–1975*. Baltimore: Johns Hopkins Press, 1960. Data for the 1955–1975 period are from "The Energy/Real Gross Domestic Product Ratio." Bureau of Economic Analysis Staff Report (U.S. Dept. of Commerce), prepared by Jack Alterman. The Alterman data were adjusted by linking to series used for the 1880–1975 period.

automobiles, insulation that makes the same level of comfort available with less energy, and the utilization of waste heat generated in various processes.

Greater efficiency in energy use is likely to be the natural result of higher energy prices, programs being launched to provide consumers with information on energy conservation opportunities, and incentives for the consumer to practice conservation. These effects will be enhanced by new energy-conserving technologies in the home, in industry, and in commerce that are certain to emerge and become cost-effective under higher energy prices. Such developments are now under way and are bound to accelerate in the future.

Here again, though, we run up against the lack of a firm fact base for predicting how large these impacts will be. It simply is not known how responsive energy demands will be in the long run to relative increases in energy prices. The available factual record was written in a period when energy prices were generally low, and therefore it cannot tell us what to expect in price-demand relationships during a period when relative energy prices are expected to be much higher. Nor is it known to what extent the response of demand to price rises will be modified by demand responses to the higher incomes that also will prevail in the future. Also, just as the consumer products that emerged in the past and created new markets could not have been predicted, so we cannot know today what product developments will take place in the future. To be sure, with higher energy prices it is likely that such products individually will tend to be more energy-efficient than in the past, but what their aggregative impact on energy demands will be is impossible to say.

It is also to be expected that in the future the composition of national output will shift toward goods and services that are less energy-intensive. In general, service activities, which are playing an ever-larger role in the output of advanced economies, require less energy than does the manufacture of most goods. For these reasons alone, GNP growth should require a lower rate of energy growth in the future.

Caution advised

Yet a word of caution is called for. Services are highly heterogeneous and some of them may turn out to be quite energy-intensive. For example, consider leisure activities, which in the future will account for an increasingly large percentage of the personal services consumers in advanced economies will demand. It is not unusual for people to travel great distances by airplane or automobile for a skiing weekend or to engage in other types of leisure activity that require substantial travel. This is, obviously, an energy-intensive form of service. There is also a growing trend in second homes — the future counterpart, perhaps, of the earlier phenomenon of second and third cars. The construction of such homes and the travel required to go from the city residence to the weekend house may both turn out to be comparatively energy-intensive. Thus, we should not fall into the trap of believing that the growth of nonindustrial activities in the future will necessarily be associated with lower intensities of energy use.

In trying to evaluate how energy demands in the future will differ from those in the past, the absence of a dependable fact base must be recognized. A growing amount of valuable research is becoming available, designed to extract insight into future dynamics from the existing body of economic statistics, including international energy use comparisons. Statisticians and economists will be squeezing the data very hard with the aid of sophisticated methodologies and imaginative research approaches. Such research is vitally important, but expectations should be modest because of circumstances to be expected in the future that are vastly different from those of the past. It will be important, in my judgment, to supplement econometric approaches, which rely essentially on historical data, with research approaches from other social sciences that may yield improved behavioral insights applicable to the future. Greater attention should also be devoted to engineering data and comparative international practices, which serve to set forth the range of feasible technology alternatives for energy use that might become economically attractive as energy prices rise.

Energy supply and economic growth

One of the most neglected chapters in energy analysis concerns the effects on economic growth of changes in the conditions of energy supply. During the past century, as noted earlier, there have been several profound changes in the composition of energy supply, including the emergence of essentially new energy forms, such as electricity. Particularly noteworthy is how these changes in energy supply technology have served to remove constraints that otherwise would have severely impeded the rate and diversity of economic growth and development. Again, let me illustrate with a brief examination of U.S. experience.

As late as 1870, about three-quarters of all the energy used in the United States was still coming from fuel wood, but the transition to coal was under way and coal soon became the dominant source. What was of primary significance in this transition was not that coal could substitute for wood in existing energy uses but rather that this was a change from a fuel resource severely limited in supply to another available in apparently endless amounts. The use of coal thus opened the way for the large-scale, unimpeded growth of iron and steel production. Ample supplies of iron and steel, in turn, made it possible to build and operate a railroad network that blanketed the country and to produce the machines required for the expansion of manufacturing. Once the fuel constraint was broken, one development led to another in a dynamic sequence that laid the foundation for modern industrial society.

In the twentieth century, as the composition of energy supply moved toward liquid fuels and electricity, other major constraints to economic growth were overcome. Electricity and the electric motor removed the limitations imposed on factory processes by the earlier mechanical energy systems, which used shafts and belting to transmit power from the in-house prime mover. Through the reorganization of factory production, which they made possible, electricity and the electric motor paved the way for large-scale productivity increases in manufacturing. Liquid fuels, the tractor, and energy-based fertilizers led to enormous increases in crop yields by removing the limits that had been imposed on agriculture by the availability of natural fertilizers and by animal draft power. And as agricultural productivity rose, farm workers became available for other sectors of production.

Geographic constraints also were removed through developments in energy supply. During the nineteenth century, railroad transportation and the mobility of coal removed the strict limits formerly imposed on industrial locations by waterways required for transportation and water wheels needed for mechanical power. In the twentieth century, the truck and the automobile broadened the availability of transportation routes, and the coming of liquid and gaseous fuels further increased the mobility of fuels, thereby removing the constraints on industrial locations previously imposed by railroads and coal. More recently, air conditioning and air transportation have removed other limitations to economic growth in many regions of the United States and the world.

The removal of all these constraints has resulted in national, regional, and local development and growth; increased productivity in industry, agriculture, and transportation; greater production of goods and services for human consumption; and marked improvements in personal living comforts and amenities. It is important to observe that in these adaptations, energy was not substituted marginally for other factors of production, such as capital and labor, which could have produced essentially the same final outcomes. Instead, energy supply and associated technologies made practical by developments in energy supply together produced results that could not have been achieved in other ways.

Supply as constraint

I want to draw particular attention to the relationship between developments in energy supply and associated developments in the capital equipment used in industry, transportation, and agriculture. The reason for emphasizing this relationship is that most econometric energy models assume (contrary to what history teaches) that the conditions under which energy is supplied in the future will not impede future productivity growth. Both capital formation and productivity are taken to be unrelated to energy development in most models.

But if energy supply and associated capital equipment have fostered rising productivity in the past, can it be assumed that major changes in energy supply conditions—that is, considerably higher prices and constrained availability—will not seriously impair productivity growth in the future? This critical issue is usually "assumed away" in econometric models of the relationship between energy and economic growth, which leads to research conclusions that may seriously underestimate the effects of energy supply constraints on economic growth in the future. My own reading of the evolution of energy-economic relationships leads me to conclude that supply effects are critically important and that strong policy efforts will be needed to prevent energy supply itself from becoming a constraint on economic growth. It is very worrisome to contemplate a future in which energy supply—the constraint-breaker par excellence in the past—becomes a constraint itself.

This is a tremendously important consideration because there is a pervasive mood of pessimism today concerning energy supply for the future. The mood reflects the conjuncture of a number of separate events—in particular, the Arab oil embargo of 1973; OPEC's imposition of massive price increases on internationally traded oil; the emergence of widespread concern over the environmental impacts of energy processes; and in the United States, a shortage in natural gas supplies. Many have jumped to the conclusion that these separate events point to a fundamental structural change in the underlying conditions of energy supply, a change with which the world will be forced to live forever. But we should be exceedingly cautious in accepting such a conclusion.

Two propositions are usually offered to support the view that a permanent structural change is in the making: (1) the world is running out of its mineral fuel resources, particularly those needed for the production of liquids and gases, and/or (2) the costs to the environment and human health and safety of continued expansion of energy supply and use that are based on mineral fuels will be too severe for society to bear.

Sound policies needed

There is ample evidence that these propositions stand on shaky ground. The dilemma, however, is that the "facts," as they will be revealed by future developments, will be largely determined by the policies now put into effect. In other words, the factual *preconceptions* of policy actions may themselves be the most important determinants of eventual outcomes. This emphasizes the need for pursuing policies whose objective is to surmount supply and environmental constraints in an acceptable manner rather than to bow to their supposed inevitability.

To devise positive approaches to the simultaneous achievement of energy supply and environmental objectives is probably the most urgent task energy policy faces today. Unfortunately, it does not appear to be receiving the attention it deserves. We continue to be transfixed by the adversary aspects of the energy-environment conflict, while the needs of the future cry out for technical and institutional solutions that will permit forward movement on both energy supply and environmental protection.

Market Potential for New Coal Technologies

by Dwain Spencer and Oliver Gildersleeve

What basis do we have for establishing R&D priorities? Generation-expansion analyses on six utility models have produced initial estimates of regional market potential for 12 options between 1985 and 2005.

The ability to compare alternative systems for electric power production is an obvious need in any scheme for setting R&D priorities among those systems. This need pervades most programs of the Electric Power Research Institute, but nowhere is it more apparent or urgent than among the often subtly varying processes proposed for using coal and coal-derived fuels.

A preliminary EPRI methodology for comparison was reported in the *Journal* a year and a half ago. "Clean Coal: What Will It Cost at the Busbar?" (November 1976, pp. 6–13) focused on the fewest possible variables: sulfur content criteria for coal fuels, power processes, and the environment; and plant capital, O&M, and fuel costs. Since then we have been developing an analytic approach that permits more meaningful comparison of alternatives.

Specifically, this approach adapts utility system generation-expansion techniques for evaluating new coal and coal-derived fuel power systems, as well as the options used today. The result is a consistent economic analysis that (1) defines the most appropriate role of each technology in the generation mix, (2) yields the market penetration potential for each technology, (3) shows the degree by which some technologies must improve to become economic, and (4) estimates the present-value savings and cost-benefit ratios that may be achieved if successful R&D results are put into practice.

Although the work to date is only a first go-around, the methodology and its initial results are deemed significant. During the last year our Advanced Fossil Power Systems Task Force has reviewed and endorsed this approach for evaluating new power plant options.

Twelve analytic steps

Recognizing that few—if any—advanced fossil power systems can be commercially available in less than seven or eight years, our evaluation begins in 1985 and involves the following:

- Development of a 1985 data base of regionally representative utility systems and generation mixes to serve as a starting point
- Projection of load growth for these utilities for the period 1985–2005
- Adoption of policy assumptions and a computer program to govern the generation expansion
- Estimation of power plant costs (capital, O&M, and fuel) on the basis of stated emission standards
- Determination of the economic penetration potential for each technology on each utility system
- Projection of these results to the U.S. market potential for all investor-owned utilities
- Identification of the technologies that justify highest priority for R&D; definition of the target costs and performance requirements for other technologies
- Iteration of the results to assess cost-performance sensitivities, market splits between close competitors, and the ef-

Dwain Spencer is director of the Advanced Fossil Power Systems Department in EPRI's Fossil Fuel and Advanced Systems Division. Oliver Gildersleeve is project manager for utility systems analysis in the division's Program Integration and Evaluation office. This article is based on their paper, "An Initial Comparative Analysis of the Market Penetration Potential of Coal and Coal-Derived Fuels in the U.S. Utility Industry (1985–2005)." The paper was written with René Loth, technical manager of economic and utility systems analysis for EPRI's Fossil Fuel and Advanced Systems Division; the complete version will appear in *IEEE Transactions on Power Apparatus and Systems*, fects of intangible factors on expansion decisions

▫ Submission of the results to selected utilities for validation or modification

▫ Estimation of costs and cash-flow requirements to complete R&D and initial commercialization

▫ Prioritization of R&D efforts by use of a present-worth cost-benefit approach

▫ Extension of the results to noninvestor-owned utilities

This article reviews conduct of the first eight steps of the analysis and presents the market potential thus indicated for power technologies using coal and coal-derived liquid fuels during the period 1985–2005.

Synthetic utility data base

For an analytic and market data base we used six mathematical models of electric utilities—"synthetic" utilities created from authentic data to simulate distinctive circumstances of regional character, generation mix, load pattern, and other factors (Table 1). These had been developed to include 1985 estimates of load and generation mix based on an analysis of utility system projections for the nine National Electric Reliability Council regions.

For each synthetic utility, typical data were estimated for daily, weekly, and monthly load cycles. The resulting load profiles were assumed constant during the period 1985–2005. For R&D planning, we also assumed 5.6% average annual growth in electric energy demand and in peak load on each system. Since load growth projections, even to 1985, are quite uncertain, it was felt that a uniform average growth rate beyond that time was adequate for this first study. Each system was also assigned an initial reserve margin of 20%, with the resulting reliability criterion held constant thereafter.

Expansion program and assumptions

A General Electric Co. program for optimized generation planning (OGP-3) was used to conduct the expansion analysis. It integrates reliability, production costing, and investment analyses into an automated, iterative generation expansion tool. Relatively coarse methods are

The Utility Data Base: 1985

Models of six "synthetic" utilities embody projections of system characteristics used as the starting point for 20-year generation-expansion studies.

Table 1
REGIONAL UTILITY MODELS

Utility Model	U.S. Geographic Region	Annual Load Factor	Summer/Winter Peak Ratio	Generation Mix (% of capacity): Steam Turbine: Coal	Steam Turbine: Nuclear	Steam Turbine: Oil	Steam Turbine: Gas	Combustion Turbine	Hydro and Storage	System Capacity (MW)	Number of Units
A	Central	0.59	1.25	57	20	7	0	8	8	11,275	49
B	Western	0.69	0.95	20	10	24	0	6	40	10,000	27
C	Midwestern	0.57	1.15	50	20	15	0	5	10	10,950	58
D	Mid-Atlantic	0.59	1.3	34	22	24	0	13	7	10,850	55
E	Gulf Coast	0.56	1.5	23	14	6	45	5	7	11,100	36
F	Northeast/ South Atlantic	0.63	1.1	9	32	45	0	5	9	10,700	34

used in its algorithms to accommodate the hour-by-hour economic dispatch of generating units at reasonable analytic cost. The OGP-3 reliability routine adjusts generating capacity for maintenance outages and uses monthly peak-load levels to determine loss-of-load probability for the system.

There were a number of limitations and simplifying assumptions in the version of the computer program and in the data used in this study. These included:

□ The OGP-3 program could accommodate no more than 6 generation types plus hydroelectric and pumped hydro storage. (We were considering some 20 types of alternative generation, and the screening matrix used to select viable candidates is described later in this article.)

□ Only one type of generation could be added in a given year.

□ Energy storage additions could not be optimized automatically. In this study, each utility was assigned a minimum energy storage component of 7%, and this proportion was maintained throughout.

□ Outages were represented as extended maintenance. Because of this modeling approach, peaking units (especially combustion turbines) did not operate as many hours as they would if outages had been represented by randomly eliminating generating units from operation.

□ Planned and forced outage data were required in OGP-3. Because there is no historical record for new power plant types, a procedure was developed for calculating self-consistent outage rates relative to conventional generation types.

□ The annual cost of ownership was treated as a fixed charge rate of 18%. This factor was applied to the total capital requirement for a plant, which was derived from a base plant cost by allowing for contingency, estimating uncertainties, interest during construction, startup costs, and escalation to the date of its addition.

Despite these limitations and assumptions, a significant advantage of the OGP-3 approach is that it determines plant capacity factor. In contrast, other economic evaluations require that capacity factors be assumed (for peaking, intermediate, and baseload generation) without regard to the initial mix of generation units and without regard to changes in mix with the passage of time. Thus, OGP-3 can identify new generation options that appear to become economic but find no market. This can happen if the generation mix in place precludes operation of the new options at viable capacity factors.

Cost and performance data

Twelve advanced options for firing coal—under a boiler or in a combined cycle—were included in the study, in addition to conventional nuclear, oil cycling, combustion-turbine, and low-sulfur coal plants (Table 2). Heat rates for cycling plants (intermediate load) were assumed to be 5% higher than those tabulated for baseload operation. The data used in this initial study are those available as of early 1976—essentially the same as presented in the November 1976 issue of the *Journal*. However, because of their application in the OGP-3 program, this study should be viewed as an extension of methodology rather than as an update. The data have more recently been regionalized and are still undergoing revision as EPRI projects produce new information. The original data are summarized here in order to identify the basis for the results obtained.

Capital Costs We attempted to obtain consistent estimates for new generation alternatives fueled by coal or coal-derived fuels. Therefore, because the input data were derived from the work of numerous EPRI contractors, we requested cost estimates for a 1000-MW coal plant using Illinois No. 6 coal and limestone scrubbers as a normalizing approach. These estimates agreed within 5%.

All plant cost estimates were adjusted to include contingency and estimating uncertainty. For conventional coal, oil, or light water reactor power plants, a 10% contingency and a $\pm 10\%$ uncertainty were used, and for new technologies the contingency factor was 20% and the uncertainty factor was -15% to $+25\%$. Between the resulting cost extremes for each plant or technology, an average figure (including interest during construction and startup costs) was derived for use in the analysis. (Sensitivity analyses are yet to be performed to consider the influence of optimistic and pessimistic cost estimates.)

Plant cost estimates for coal-fired and coal-derived fuel plants were based on meeting the 1975 New Source Performance Standard (NSPS) for sulfur dioxide emissions (1.2 lb $SO_2/10^6$ Btu). More stringent emission controls would change the relative performance of alternative systems and clearly would change their relative economics.

The capital requirements shown in Table 2 include interest during construction, estimated at 23% for nuclear plants (7½-year construction cost exposure period), 20% for coal-fired and gasification units (6-year construction period), and 14% for petroleum-type combined-cycle plants (3½-year construction period). The figures also include 10% startup costs for nuclear plants and 8% for other steam plants. For gasification plants, the capital requirement includes all costs from coal to busbar; whereas for plants using solvent-refined coal (SRC) and petroleum-type fuel (PTF), only the power plant total capital requirement is shown. Projected capital requirements of the conversion facilities for these fuels are included in the prices of the fuels themselves.

Fuel Costs For a given fuel type in each synthetic utility region, the lowest price fuel source was used (Table 3). For instance, where low-sulfur subbituminous or lignite from the western plains would be available at a lower price than eastern low-sulfur coal, only the western coal was considered. Coal heating values of

Table 2

PLANT PERFORMANCE PARAMETERS AND CAPITAL COSTS

Unit Type	Unit Capacity (MW)	Year Available	Baseload Heat Rate (Btu/kWh)	Capital Cost (1975 $/kW)
Steam Plants[1]				
Nuclear (light water reactor)	1000 1300	1980 1980	10,300	720
Oil (cycler)	400 500 600	1980 1980 1980	9,200	375
Low-sulfur coal	800 1000 1300	1980 1980 1990	9,000	415
Coal (limestone scrubber)	Same as low-sulfur coal		9,500	555
Coal (regenerative scrubber)	Same as low-sulfur coal		10,000	650
Atmospheric fluidized-bed combustion (AFBC)	400 600 1000	1985 1990 1995	9,500	530
Solvent-refined coal (SRC)	400 1000	1985 1990	9,000[3]	425
Petroleum-type fuel (PTF)	Same as SRC		9,000[3]	275
Moving-bed gasifier (low-Btu)	400 600 1000	1985 1990 1995	13,500	880
Slagging gasifier (medium-Btu)	Same as moving-bed gasifier		11,300	670
Entrained gasifier (low-Btu)	Same as moving-bed gasifier		10,600	600
Combustion Turbine Plants	75 100 150	1980 1990 1995	12,000[4]	135
Combined-Cycle Plants[2]				
Petroleum-type fuel (PTF)	400 800	1985 1990	7,500[3]	220
Moving-bed gasifier (low-Btu)	Same as PTF		9,500	760
Slagging gasifier (medium-Btu)	Same as PTF		9,100	575
Entrained gasifier (low-Btu)	Same as PTF		8,400	540

[1]Steam turbine inlet conditions: 16.5 MPa (2400 psi), 540°C (1000°F) superheat, 540°C (1000°F) reheat.
[2]Gas turbine inlet temperature 1200°C (2200°F), compression ratio 16:1; coupled to a steam bottoming cycle at 16.5 MPa (2400 psi) and 540°C (1000°F).
[3]Power plant only, not including losses in coal conversion.
[4]Peak load.

Table 3

PLANT FUEL COSTS

(1975 $/$10^6$ Btu)

	Utility Model					
Fuel Type	A	B	C	D	E	F
Nuclear fuel (new)	0.45	0.45	0.45	0.45	0.45	0.45
Residual oil	2.00	2.25	2.25	2.00	2.00	2.00
Distillate oil	2.25	2.50	2.50	2.25	2.25	2.25
High-sulfur coal (eastern)	1.00	*	*	1.00	1.00	1.10
Low-sulfur coal (eastern)	1.25	*	*	1.25	1.25	1.35
Subbituminous or lignite coal (western)	1.15	0.80	0.80	1.25	1.00	1.30
Solvent-refined coal (SRC)	2.35	*	*	2.35	2.35	2.45
Petroleum-type fuel (PTF)	3.00	3.00	3.00	3.00	3.00	3.10
Natural gas	NA	NA	NA	NA	1.90	NA

*Preempted by lower-cost western coal.

Table 4

PLANT OPERATING AND MAINTENANCE COSTS

(1975 $)

Unit Type	Fixed ($/kW·yr)	Variable (mills/kWh)	Reag[illegible] ($/$10^6$[illegible]
Steam Plants			
Nuclear (light water reactor)	5.40	0.30	—
Oil (cycler)	2.60	0.50	—
Low-sulfur coal	1.65	0.45	—
Coal (limestone scrubber)	3.50	1.25	0.1[illegible]
Coal (regenerative scrubber)	3.55	1.75	—
Atmospheric fluidized-bed combustion (AFBC)	4.00	2.10	0.3[illegible]
Solvent-refined coal (SRC)	1.75	0.45	—
Petroleum-type fuel (PTF)	1.90	0.15	—
Moving-bed gasifier (low-Btu)	6.35	3.10	—
Slagging gasifier (medium-Btu)	5.10	2.45	—
Entrained gasifier (low-Btu)	4.50	2.00	—
Combustion Turbine Plants	0.25	4.95	
Combined-Cycle Plants			
Petroleum-type fuel (PTF)	1.10	0.75	—
Moving-bed gasifier (low-Btu)	5.40	4.25	—
Slagging gasifier (medium-Btu)	3.90	3.20	—
Entrained gasifier (low-Btu)	3.55	2.80	—

Table 5

UNIT AVAILABILITY

Unit Type[1]	*Planned Outage (% of yr)*	*Mature Forced Outage (% of period)*[2]	*Availability (% of yr)*
Steam Plants			
Nuclear (light water reactor)	15	15	72
Oil (cycler) (500 MW)	10	7	84
Low-sulfur coal	10	15	77
Coal (limestone scrubber)	10	18	73
Coal (regenerative scrubber)	10	18	73
Atmospheric fluidized-bed combustion (AFBC)	10	9	82
Solvent-refined coal (SRC)	10	15	77
Petroleum-type fuel (PTF)	10	5	86
Moving-bed gasifier (low-Btu)	10	9	82
Slagging gasifier (medium-Btu)	10	14	77
Entrained gasifier (low-Btu)	10	13	78
Combustion Turbine Plants	5	15	81
Combined-Cycle Plants			
Petroleum-type fuel (PTF)	10	7	84
Moving-bed gasifier (low-Btu)	10	10	81
Slagging gasifier (medium-Btu)	10	12	79
Entrained gasifier (low-Btu)	10	11	80

[1]Steam plants 1000-MW capacity except where noted; combustion turbine plants 100-MW; combined-cycle plants 800-MW.
[2]Period defined as one year less time for planned maintenance.

Table 6

PLANT AND FUEL COST ESCALATION FACTORS

Parameter	*Multiplier 1975–1984*	*Annual Percentage 1985–1989*	*1990–1994*	*1995–2005*
Power plants	1.69	4	4	4
Nuclear fuel (new)	1.79	6	6	8
Residual oil	1.92	6.95	4	8
Distillate oil	1.90	5.9	4	8
Eastern coal, limestone, solvent-refined coal, petroleum-type fuel	1.54	4	4	4
Low-sulfur coal (eastern)	1.54	4	4	8
Subbituminous or lignite coal (western)	1.52	4	4	4
Natural gas	2.16	8	8	8

26.4×10^6 and 18.3×10^6 Btu/t were assumed for eastern and western coals, respectively.

Of the two coal-derived fuels, SRC is a solid at room temperature and PTF is a refined coal liquefaction product suitable for firing combustion turbines and combined-cycle plants. The tabulated prices of these fuels account for the capital and operating costs of the fuel conversion plants—dedicated facilities that would operate independently of the dispatch schedules of the power plants using their products. Present cost estimates for producing SRC and PTF indicate their prices will be nearer $2.50–$2.75/10^6 Btu (for SRC) and $3.50–$3.75/10^6 Btu (for PTF) in 1975 dollars. These latter estimates will be considered in future iterations, but a limited analysis for a wide range of PTF prices is noted later in this article.

Operation and Maintenance Costs A consistent set of O&M costs (other than fuel) has been obtained by factoring the plant capital costs. Typical factors for utility and chemical equipment were applied as appropriate and the results split into fixed and variable costs in 1975 dollars (Table 4). O&M rates are defined for 1000-MW units and scaled up for the smaller unit sizes represented in the initial generation mix.

One significant additional operating cost—for plants directly firing high-sulfur coal—is that of reagents used for sulfur removal. For wet alkali scrubbing, approximately 0.15 t limestone is required per ton of coal. For atmospheric fluidized-bed combustion (AFBC) units, stoichiometric requirements for sulfur removal are uncertain, but they range from 0.3 to 0.6 t limestone or dolomite per ton of coal. In this analysis we assumed a delivered reagent price of $26.40/t, which includes both delivery and disposal. In future studies, the cost of waste disposal will be estimated separately for the various processes, and reagent prices in the range of $6–$12/t will be used.

Unit Availability Because there are no data on unit availability for new types of generation, it was necessary to develop a forced-outage rate analysis to provide values consistent with those for conventional generation. Planned outages were arbitrarily set at 10% of the year (about five weeks) for most types and 15% for nuclear units (to account for reactor core refueling). The analysis estimates mature forced-outage rates as a percent of the year left after planned maintenance is excluded (Table 5).

Escalation A major uncertainty in any analysis projecting comparative economics in the future is the rates of escalation for generating equipment, fuel, and O&M costs. In this analysis, escalation has been separately treated for the period from 1975 through 1984 and for the long term beginning in 1985 (the initial date for this study).

Table 6 summarizes the escalation rates (including inflation) used for power plants and fuels. The long-term inflation rate used was 4% per year and the associated discount rate was 10%. Beyond 1985 the rate of escalation was held constant, except for fuels nearing resource exhaustion (oil, uranium, and low-sulfur eastern coal). In these cases, 4% per year was added to the escalation rate, beginning in 1995. Natural gas was assumed to be available in 1985 only for the synthetic utility representative of those in the Gulf Coast region, and it was escalated at 8% per year. Since O&M costs were derived from plant capital costs, they escalate at the same rate as plant costs.

Screening to reduce options

To limit the number of actual runs performed with OGP-3 (because it is capable of evaluating only six types of alternative generating units in a run), a screening approach was developed to identify competitive domains defined by future plant, fuel, and O&M costs. A domain boundary represents identical busbar energy costs from two generation options. When plotted, the results appear similar to a material-science phase diagram. Thus these screening charts are referred to as generation phase diagrams (Figure 1). Derived from the input data,

Generation Expansion Alternatives: 1985–2005

Technologies (by fuel type) are grouped to differentiate futures with and without the influence of new coal-based options. Selection of utility models is based on the applicability of fuels to specific regions.

Table 7

TWO TECHNOLOGY FUTURES

Generation Type	*Utility Models*
Present Technology Only	
Nuclear (light water reactor)	A–F
Distillate oil (combustion turbine, combined cycle)	A–F
Low-sulfur coal	
Eastern	D, F
Western	A–C, E
Coal (limestone scrubber)	A, D–F
Pumped hydro (after 1985)	A, C–F
All R&D Successful	
Nuclear (light water reactor)	A–F
Distillate oil (combustion turbine, combined cycle	A–F
Low-sulfur coal	
Eastern	D, F
Western	A–C, E
Petroleum-type fuel (combustion turbine, combined cycle)	A–F
Entrained gasifier (low-Btu) (combined cycle)	A, D–F
Pumped hydro	A, C–F
Coal (limestone scrubber)	A, D–F

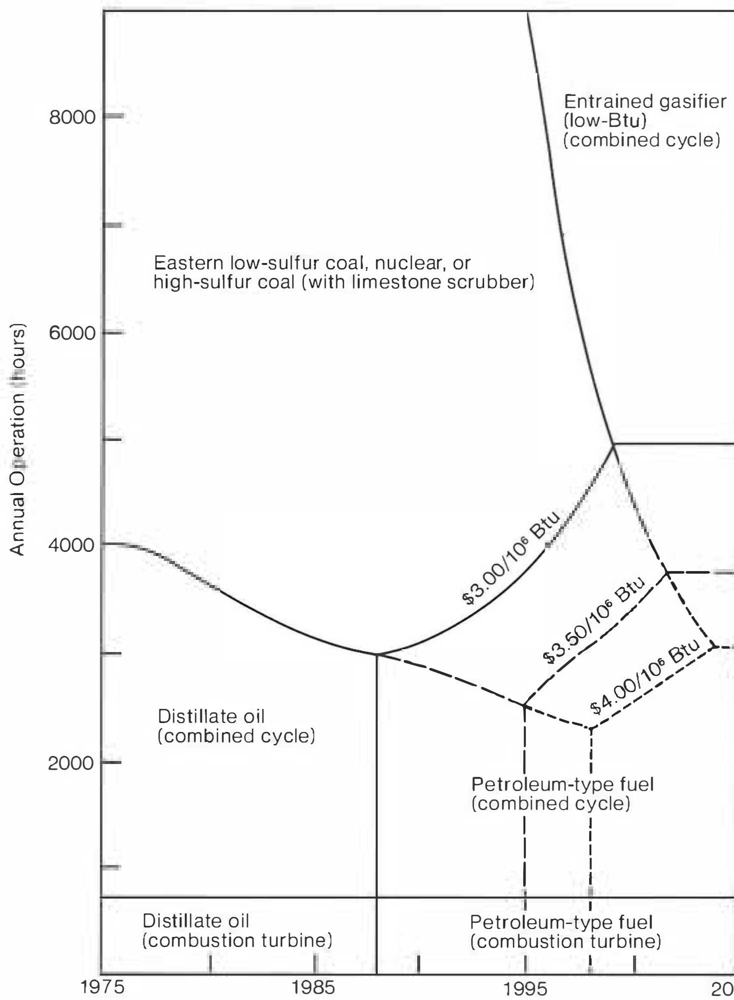


Figure 1 This generation phase diagram represents synthetic utility model D and one set of fuel costs. Only the most economically viable technologies appear—that is, only those generation alternatives (by fuel type) that have minimum busbar energy costs for some span of capacity factors in the initial year of their use.

Table 8

REGIONAL SYSTEM CAPACITY ADDITIONS ASSUMING PRESENT TECHNOLOGIES ONLY

(%)

	Utility Model					
Generation Type	*A*	*B*	*C*	*D*	*E*	*F*
Nuclear light water reactor or low-sulfur eastern coal or western subbituminous or lignite coal	78	87	—	58	95	58
Western subbituminous or lignite coal	—	—	72	—	—	—
High-sulfur eastern coal (limestone scrubber)	—	—	—	33	—	35
Combustion turbine (distillate or residual oil)	14	13	28	7	3	7
Combined cycle (distillate or residual oil)	8	—	—	2	2	—
Total additions	100	100	100	100	100	100

Table 9

REGIONAL SYSTEM CAPACITY ADDITIONS ASSUMING SUCCESSFUL R&D IN NEW COAL-BASED TECHNOLOGIES

(%)

	Utility Model					
Generation Type	*A*	*B*	*C*	*D*	*E*	*F*
Nuclear light water reactor or low-sulfur eastern coal or western subbituminous or lignite coal	67	81	—	39	87	56
Western subbituminous or lignite coal	—	—	72	—	—	—
High-sulfur eastern coal (limestone scrubber)	—	—	—	—	—	—
Combustion turbine (distillate, residual or petroleum-type fuel)	16	19	28	8	13	12
Combined cycle (distillate, residual, or petroleum-type fuel)	17	—	—	39	—	32
Entrained gasifier (low-Btu) (combined cycle)	—	—	—	14	—	—
Total additions	100	100	100	100	100	100
Year of Conversion From Oil to Coal-Derived Petroleum-Type Fuels						
Distillate	1989	1985	1985	1989	1989	1995
Residual	1996	1987	1989	1996	1996	1997

Table 10

UTILITY MARKET POTENTIAL AND DISTRIBUTION OF COAL-DERIVED LIQUID FUELS

		Application (%)		
Year	*Fuel Volume* (10^6 bbl/d)*	*Existing Boilers*	*Combined Cycles*	*Combustion Turbines*
1985	0.01	—	—	100
1990	0.40	92	—	8
1995	0.85	34	52	14
2000	2.55	39	53	8
2005	3.70	28	64	8

*At $3.00 10^6 Btu, 1975 $.

Table 11

UTILITY MARKET SENSITIVITY OF COAL-DERIVED LIQUID FUELS

(10^6 bbl/d)

	Price*		
Market	*3.00*	*3.50*	*4.00*
1985	0.01	—	—
1990	0.40	—	—
1995	0.85	0.03	—
2000	2.55	0.50	0.06
2005	3.70	0.95	0.50

*1975 $/$10^6$ Btu

they include the effects of future fuel prices (10-year levelization) and assume equal generating unit reliabilities with no planned unit outages. Thus, this approach screens out any uneconomical alternatives; computing costs are reduced, and OGP-3 limitations accommodated.

Market potential

Based on the screening analysis, only the generation alternatives shown in Table 7 were used in the OGP-3 program. To obtain an estimate of the benefit-cost relationship of coal technology development, two cases were run: first, assuming present technology only (Table 8), and second, assuming all coal R&D is successful and that the cost and performance projections for each alternative are realized (Table 9).

From Table 8 it is apparent that without new technology, light water reactors and low-sulfur coal-fired plants would be preferable for baseload throughout the country. However, as low-sulfur coal and nuclear fuel prices rise, high-sulfur coal plants with scrubbers would enter the market. Further, should either or both of these fuels become resource- or production-limited earlier than 1995, a greater demand for high-sulfur coal-fired plants would emerge. Thus there is a significant incentive to develop highly reliable coal-fired plants with scrubbers having low parasitic loads.

Table 8 also indicates a continuing market potential for combustion turbines in all regions, but a very limited market for combined-cycle plants if only distillate oil is available.

Table 9 reveals two major changes if coal conversion technology is successful: the combined-cycle market is increased significantly in Regions A, D, and F, and the fraction of combustion-turbine additions is increased substantially in Regions B, E, and F. Also, the low-Btu entrained-gasifier combined-cycle option begins to penetrate in Region D.

The most significant implication of this comparison is the added penetration of combined cycles if PTF coal liquefaction is successful because Regions A, D, and F together represent approximately 60% of the projected U.S. utility capacity. This penetration, of course, is based on a PTF price of $\$3.00/10^6$ Btu (in 1975 dollars).

The estimated market potential for coal liquids in the electric utility industry is shown in Table 10. Based on this analysis, there appears to be a substantial electric utility market potential for coal liquids if present cost objectives are met and alternative liquid fuel costs escalate as projected.

Fuel Price Sensitivity To demonstrate the flexibility of the analytic method, we also considered two additional coal-liquid prices. The assumed values are $\$3.50/10^6$ Btu and $\$4.00/10^6$ Btu (in 1975 dollars). These estimates bracket the presently projected prices for coal liquids from commercial fuel plants using either the H-Coal or the Exxon Donor Solvent process.

As may be seen from Table 11, the market potential for coal liquids is quite sensitive over this price range. Based on the uncertainty of these prices and of future price escalation in other liquid fuels, we consider it a high priority for the electric utility industry to continue R&D toward the demonstration of coal liquids.

Coal R&D priority

One objective of assessing market potential was—and is—to develop a benefit-cost ratio for R&D expenditures on advanced coal and coal conversion technologies. We have conducted a rudimentary analysis by comparing the penetration of new technologies (Table 8) with that of present technology (Table 9). For those new coal technologies that may penetrate the market between 1985 and 2005, the estimated net savings to the electric utility industry were present-valued to 1976 dollars. The resulting figure was compared with EPRI's planned expenditures in new coal technology from 1976 to 1985 and also compared on a national basis with the planned expenditures of the Department of Energy (DOE).

This first-cut comparison constitutes a benefit-cost ratio of 20:1 for utility investment. Assuming that DOE expenditures in this R&D area are about 10 times those of EPRI, the national benefit-cost ratio would be 2:1. It should be noted that neither ratio includes credits for the value of decreased environmental emissions inherent in the use of advanced coal technologies. Our conclusion is the firm belief that the ratios are ample incentive for continued utility and federal investment in coal R&D oriented toward electric utility requirements.

Further avenues of analysis

This article has reviewed the methodology of an internal study, its first use, and the results. To validate or modify our early conclusions, we are now pursuing four avenues of continued analysis:

- Iteration of all cost and performance estimates, with emphasis on regional plant cost differences
- Sensitivity analyses to consider such factors as more stringent future environmental regulations, limitations to the electric utility industry on low-sulfur eastern coal and on oil, and a range of plant and fuel price escalations
- A research project involving utility planning departments to determine whether the results remain valid when using different generation expansion models, utility projections for fuel escalations, and other utility decision criteria
- Consideration of other advanced coal utilization systems, such as fuel cells using low-Btu gas, open-cycle magnetohydrodynamic power plants, physical and chemical coal cleaning, and alternative flue gas desulfurization approaches

Clearly, the overall analytic effort will require many more iterations and will never really be complete. However, we believe this approach has opened a new era of evaluating R&D priorities for the electric power industry on a more quantitative, consistent basis.

Ellis T. Cox: Pragmatist With a Public Conscience

His daily decisions at Potomac Electric Power Co. ensure electricity for the U.S. capital. His leadership of EPRI's Research Advisory Committee will help to extend that ensurance across the nation and into the future.

Anyone who has ever flown into Washington's National Airport at night remembers the grandeur of gleaming white monuments unfolding against a black sky.

Ellis T. Cox is keenly aware of the need to protect the historic beauty of this sight. As executive vice president and chief operating officer of the electric utility serving the nation's capital, he is in a position to help preserve the city's unique and memorable qualities.

It's a responsibility that he and other managers at the Potomac Electric Power Co. (Pepco) take seriously. That's one reason the utility is installing expensive environmental control devices at its Potomac River plant—five coal-fired units on the Virginia side of the Potomac River, minutes away from the downtown area.

"We burn low-sulfur coal there, and we're in the process of building a hot precipitator system for all five units," he observes. (An electrostatic precipitator extracts particulate matter emitted from power plant stacks. A hot precipitator works with hot gases.)

"You may have noticed that one of the stacks over there doesn't show any smoke at all," he continues. "That particular unit and its precipitator system began operating in the latter part of 1977. We expect to finish the remaining four units with precipitators also, so that when you fly into National Airport, you won't see smoke coming out of the Potomac plant."

As Cox explains it, his company feels a moral obligation to the citizens in its service area to make sure that its power plants comply with realistic environmental regulations. By utility standards, Pepco is unusual in its lack of large industrial customers. According to the 1977 annual report, about 24% of the company's kilowatthour sales were to residential customers, with business and government accounting for the remaining portion. Indeed, the company's largest single customer is the federal government, accounting for 19% of sales in 1977.

As the electric utility serving the nation's capital, Pepco has a unique opportunity, Cox believes, to speak for the industry by setting an example of a well-run and responsible company. Among the utility's individual customers are many of the decision makers who determine national policy on energy and utility matters.

"There are 100 senators and 435 congressmen here—many of whom are our customers—not to mention Cabinet heads and even the Chief Executive himself. And if a hurricane or something of that nature causes a blackout in a portion of our service area, we should be able to restore service rapidly; otherwise, it could reflect on the efficiency of the entire industry. So I think we have an obligation to manage our affairs in an exemplary manner."

To Cox, this means not only living up to civic responsibilities, such as protecting air and water quality, but also demonstrating that the company is run as an efficient, cost-conscious enterprise. There are dual facets of Ellis Cox's personality that show through when he discusses his management philosophy and career. On the one hand he is a pragmatic businessman, talking in terms of "wise and prudent management," "costs and benefits," and "realistic regulations"; and on the other hand he is deeply concerned with matters of ethics and conscience—with "commitments," "wise judgments," and "moral obligations."

Cox recently discussed his career, philosophy, and management style in the context of his role as the new chairman of EPRI's Research Advisory Committee (RAC), the senior group in the Institute's advisory structure. RAC consists of utility executives who guide EPRI's president and Board of Directors in identifying and ranking the R&D needs of the industry. Although Cox is new to the chairman's job, he is no stranger to RAC, having served as a member for the past year. He is RAC's second chairman. The first, Ludwig P. Lischer, vice president in charge of engineering, research, and technical activities for Commonwealth Edison Co., was chairman for four years and is continuing as a member.

The new chairman has nothing but praise for his predecessor. "I think that Lud Lischer has done an outstanding job, and I am extremely proud to be the Committee's second chairman," Cox says. He already has a definite concept of the direction that RAC will be taking this year. As he explains it, "I think we have a major task ahead of us in trying to put in place a planning mechanism, a methodology, that can ensure us that we are in fact selecting the proper priorities from the many, many research efforts suggested."

What does he feel are the major problems facing the utility industry today that deserve top priority in R&D? High among them, he responds, is finding a way to secure a long-term supply of fuel, and he emphasizes that this means both coal and nuclear power.

"In this business, an assured supply of fuel is at the heart of our service," he notes. "We've got to get away from petroleum. In my judgment, petroleum should be channeled only to those industries that absolutely need it, such as the petrochemical industry and some portions of the transportation industry." Cox believes that governments have to be convinced to be realistic in requirements relating to the burning of coal, and he insists that "the only viable alternative for the future of electric generation in this country is to expand the use of nuclear power."

At the time Cox was discussing utility problems and new courses of action, the nation's coal strike had entered its third month, President Carter's energy bill was still stalled in Congress over the natural gas pricing issue, and the city was expecting its tenth snow of the season. Fuel supply problems were definitely foremost in the minds of Washington energy officials.

"I see no alternative to developing our nuclear power generation further," Cox observes. "I think that coal is an important part of our future, but I don't believe it will satisfy all our environmental requirements. We have to supplement it with nuclear power. And soon!"

"The only viable alternative for the future of electric generation is to expand the use of nuclear power."

Will the coal strike imprint on the national consciousness the vulnerability of coal as a stable fuel source?

"One would hope so, but I'm just not sure," he comments. "Coal was difficult to obtain last winter because of freezing rivers and stockpiles, but this didn't have the impact in promoting nuclear power that I had hoped it would."

Although Pepco has no nuclear plants planned or operating at the moment (the utility runs on oil and coal), two were planned at one time for the Douglas Point site in southern Maryland. Cox explains that these plants were deferred indefinitely because Pepco's load growth doesn't require additional generating facilities. Although Washington, D.C., was one of the fastest growing areas in the country during the 1960s, population growth has leveled off since that time.

He says that other utilities, however, have deferred nuclear plants and substituted fossil plants for entirely different reasons, "not the least of which is their skepticism about the availability of fuel . . . and the ability to bring a plant online on schedule. With regulatory lag and other such problems, nuclear power often is a gamble many utilities can't afford to take."

Streamlining the regulatory process is a responsibility of the government agencies involved, but fuel availability is a technical area in which the industry can make a contribution. And Cox is genuinely excited about the proposal made by EPRI President Chauncey Starr and Walter Marshall of the United Kingdom Atomic Energy Authority at the Fifth Energy Technology Conference in Washington.

Starr and Marshall proposed that a new "diversion-proof" method for reprocessing spent fuel from nuclear reactors be demonstrated as an alternative to the world's standard reprocessing technology (Purex). The new process—called Civex to emphasize its civilian nature—would eliminate the possibility that plutonium might be diverted for the fabrication of weapons. As Starr and Marshall explained it, at no time and in no place during the Civex fuel cycle would any pure, weapons-grade plutonium be present. And the plutonium that would be present in the process would always be mixed with uranium and radioactive waste products, keeping it so "hot" that anyone trying to steal it would be disabled.

"I am just delighted at what I know of the proposal," Cox states. "I think this is possibly an answer to the president's plea to find a way to use nuclear power without jeopardizing world safety. I don't have a doubt in my mind that the utilities will respond favorably—enthusiastically—to this suggestion. And I can't believe that it won't be universally accepted."

Cox stands squarely on the side of those who believe firmly that nuclear power reactors are safe—both the present generation of light water reactors and the fast breeders that the industry envisions for the future.

"Having been in the nuclear power business from 1955 through 1965 (at the Bettis Atomic Power Laboratory in Pittsburgh, Pennsylvania) and on the periphery since then, I am convinced that these plants are safe," he says. He discounts the notion that the Civex proposal was a criticism of the Purex process.

"It just gives us another route—a substitute—something that could answer the questions of a populace unconvinced that the Purex process is safe."

He believes that the Civex process will make good business sense to utilities. "I think the utilities are seeking a way to prudently manage the fuel cycle. It makes no sense to me whatsoever to be storing spent fuel. It's a waste of resources, and we hear from the president—from the last three presidents—that we must conserve our resources, our energy resources particularly. And for us to be storing fuel that is only partially utilized and partially burned is, to my way of thinking, an extremely uneconomical thing for us to be doing—and imprudent. . . ."

From the beginning, Ellis Cox has been oriented toward the pragmatic concerns of the business world. At the University of New Hampshire, he worked toward a BS in business administration, taking engineering courses on the side and working first as an apprentice and then as a journeyman electrician at the Portsmouth Naval Shipyard. After receiving his degree, he worked for 11 years for Westinghouse at the Bettis Atomic Power Laboratory, where he was manager of the surface ship project in the Naval Reactors Program. It was there that he met, worked with, and developed a strong admiration for Admiral Hyman G. Rickover, a person Cox describes as "an exceptional individual who deserves credit for a monumental achievement in making nuclear power a reality."

"To be storing fuel that is only partially utilized and partially burned is imprudent."

Cox views himself as a problem solver and looks back on the highlights of his career as those times when he went into a troubled situation, brought together an effective team of people, and solved the problem—or, when he was responsible for starting a new facility. He recalls, for example, his assignment for Westinghouse in 1967 when he was responsible for the construction and startup of a new transformer manufacturing facility in southern Virginia. He is proud of leaving there with what he considers "excellent labor relations, an excellent product line, and excellent productivity."

From Westinghouse, Cox went to Babcock & Wilcox in New York as vice president and general manager of the Power Generation Division. He came at a troubled time for that division but succeeded in reversing a loss position. Then came his affiliation with Allis-Chalmers Corp. in Milwaukee as group executive and vice president of the Power Systems Group and president of Allis-Chalmers Power Systems, Inc., an affiliate company. He left there and joined Pepco in 1972, rounding out a career that has included construction, R&D, manufacturing, engineering, and utility management.

"I feel I've been very privileged in my career," he muses, looking back on it all. "I'm so grateful for all the opportunities I've had. If something happened to me tomorrow morning, I would look back on a very, very satisfactory career."

At 58 years of age, Ellis Cox admits that he still loves to work. "I get tremendous satisfaction out of work-oriented things," he says. When he's not working, however, he enjoys reading and golfing, particularly with his family at their vacation home in Pinehurst, North Carolina.

As a business manager most of his career, Ellis Cox is well-suited for his advisory role to EPRI, an institution of R&D managers rather than R&D scientists. "There is little or no cause for basic research to be done by the EPRI staff," he says. "Basic research should be done in a laboratory somewhere."

How does he rate EPRI's program so far?

"I've been very impressed," he comments. "I don't feel at all that it's research for the sake of research. I think that it's research for the benefit of the industry."

Nearly 50% of EPRI's research program is directed toward solving near-term industry problems, with results expected by 1985, and Cox feels that this is how it should be—at least for now.

"If one were to look into the future, one would say, for example, that certainly fusion is something that we should look to as an energy source. But for EPRI to put millions and millions of dollars into that kind of program today would, I think, reduce the effort on matters that need immediate attention. We don't have an unlimited source of funds, and we must use what we have to our immediate advantage rather than go out on a limb somewhere and sacrifice today for tomorrow."

As the chief operating officer of a utility, Cox is concerned directly with practical problems that call for solutions today. Air quality control is one such problem. Cox pointed to EPRI's work on the high-intensity ionizer as an example of how the Institute has responded to that problem. The ionizer was designed to enhance fly ash collection, and it works especially well with the type of low-sulfur coal that Pepco is using at the Potomac River plant. The device imparts up to five times the charge of conventional electrostatic precipitators, and Cox sees it as the next generation of this type of equipment. It is now undergoing tests at EPRI's Emissions Control and Test Facility at the Arapahoe station of Public Service Co. of Colorado.

Another example Cox cites of an EPRI program directed toward immediate, practical problems of the industry is the work being done to improve the combustion turbine.

"This is something that the utility industry is going to need because as we bring synthetic fuels on-line—oil and gas from coal—we're going to be looking to combustion turbines in combined-cycle plants for baseload generation rather than just for peaking or intermediate use.

"I think that programs of this nature, and certainly the programs being developed in the transmission and distribution area, have immediate payoff," he observes. "So, yes, from my personal assessment, I think that EPRI's programs are of value to me and I think that we in the industry eagerly await the results of these experiments."

Cox has firsthand knowledge of EPRI's programs and management, both from his service on RAC and from his experience as a member of the RAC subcommittee that contributed to the EPRI effectiveness review last year.

"I was involved in auditing the procedures at EPRI, interviewing all the division heads, assessing whether they were in control of matters, whether their purchasing practices were sound, whether their organization was sound, whether they had good procedural control over their operations, how the requests for proposals were submitted and bids evaluated, and so on."

What did he find out? "I am greatly impressed, frankly," he says, "with the work that EPRI has done since its formation and with the administrative controls and the advisory structure."

One area that he feels EPRI can contribute more to in the future is the coordination of its research efforts with those of the federal Department of Energy.

"One of the major influences EPRI can have for the utility industry is to make certain that we work together with the Department of Energy on research programs and help in the selection process the government goes through so the federal funds channeled toward this industry are channeled wisely. I think we can work as a team—EPRI and the Department of Energy—and I feel that this is most important."

Ellis Cox feels strongly that energy decisions made by EPRI, the federal government, individual utilities, and the industry as a whole will affect the happiness and security of the people in this country. This is a great responsibility and requires that these decisions be made only after a great deal of thinking on the problems and opportunities involved.

Ellis Cox, pragmatist with a public conscience, accepts that responsibility.

At the Institute

McKinney Named Southeast Coordinator

B. G. McKinney has joined the EPRI Fossil Fuel Power Plants Department as regional coordinator of activities in the southeastern United States.

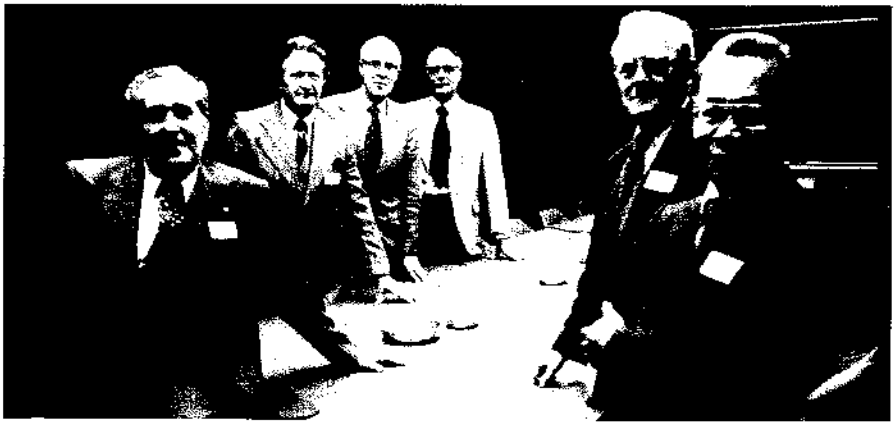
McKinney, previously a manager of energy research for the Tennessee Valley Authority (TVA), will coordinate research at the EPRI–TVA Shawnee Scrubber Test Facility in Paducah, Kentucky, as well as coordinate other EPRI cooperative projects with utilities in the Southeast. The Shawnee test facility is developing methods for removing sulfur oxides from power plant stack gas emissions.

McKinney began his professional career designing bridges in 1957, the year he graduated with a BS in civil engineering from the University of Kentucky. From 1962 to 1971, he worked as a mechanical engineer in aerospace design and research for the Army Missile Command, National Aeronautics and Space Administration, Brown Engineering, and Boeing Aerospace Co., all in Huntsville, Alabama.

In 1971, McKinney joined TVA, where he held positions as sulfur oxide and pollution projects mechanical engineer, environmental research section manager, and research manager.

McKinney received his PhD in mechanical engineering in 1969 from the University of Alabama. He is the author of several articles on heat transfer, fluid mechanics, odor control, and sulfur oxide control. He is a member of the American Society of Civil Engineers, Tau Beta Pi Association, and the Society of Sigma Xi.

Electrical Systems Task Forces Meet



Task Force chairmen for the EPRI Electrical Systems (ES) Division gather during a break in a recent orientation meeting held in Palo Alto, California. For the first time since being organized, all ES Division task forces met for information exchange and indoctrination on their functions, those of the division committee, and their relationship to EPRI staff. Shown with John Dougherty, EPRI ES Division director (left), are Jake Sabath, Southern California Edison Co. (DC Transmission Task Force); Bill Johnson, Pacific Gas and Electric Co. (Division Committee); Al Zanona, Commonwealth Edison Co. (Underground Transmission Task Force); Dave Massey, General Public Utilities Corp. (AC Transmission Task Force); and Tom Dy Liacco, The Cleveland Electric Illuminating Co. (Power System Planning and Operations Task Force). Not shown are Joe Friderichs, Philadelphia Electric Co. (Distribution Task Force), and Malcolm Johnson, South Carolina Electric & Gas Co. (Rotating Electrical Machinery Task Force).

Sulfur Oxide Standards Examined

New federal standards being imposed on utilities to reduce the sulfur oxides emitted in power plant stack gas are unnecessary, say environmental health experts who attended a recent New York Academy of Medicine symposium on the environmental effects of sulfur oxides and related particulates.

James McCarroll, manager of EPRI's Health Effects Program, says the consensus of the group was that sulfur oxides emitted into the air today by power plants do not pose a significant threat to human health.

Serious questions have thus arisen among environmental health experts about the increasingly stringent controls being imposed on utilities by the federal government. The New Source Performance Standards (NSPS) of the 1977 Clean Air Act Amendments will require utilities to spend approximately $200 billion between now and the turn of the century on stack gas scrubbers, reports McCarroll.

"In spite of the large number of power plants operating today, there has been an enormous improvement in the quality of the air in most major U.S. cities," McCarroll states. He attributes this to controls that were implemented during the past decade: "Because of these controls we should not again experience the acute air pollution episodes of the past."

McCarroll further reports that the specialists at the New York symposium concurred that there is no solid evidence to indicate the new standards will provide a significant benefit to human health. "The very large amount of money the federal government is requiring utilities to pay might be better spent on controlling other compounds with more significant health effects (such as cancer-causing agents) or used for other public health purposes," he states.

Transmission Line Book Published

EPRI recently published a transmission line design book that will help utilities improve efficiency of right-of-way use. The book describes a new technology whereby circuits can be compacted to transmit more power in less space, reducing the need for utilities to acquire additional land for transmission line rights-of-way. Del Wilson (foreground) of Power Technologies, Inc., the developer of the new technology, describes some of the book's features at an EPRI-sponsored symposium held recently in Palo Alto, California. A second symposium, also organized to familiarize transmission engineers with the new technology, was held in Essington, Pennsylvania. The reference book, *Transmission Line Reference Book: 115–138-kV Compact Line Design,* is available from Research Reports Center.

Project Highlights

New Process Promises Lower-Cost Underground Transmission

A new process for manufacturing continuous lengths of superconducting tape, developed by Los Alamos Scientific Laboratory (LASL) for EPRI, may offer the electric utility industry more efficient and less expensive underground transmission cables. The tape is coated with a combination of two elements—niobium and germanium. Like other superconductors, the combination offers unlimited conductivity for transmitting direct current at extremely cold temperatures.

This new tape is unique because it operates at a warmer temperature than other superconductors being developed today. It therefore requires less refrigeration and enables the development of simpler, more reliable, and less costly cryogenic (low-temperature) systems for superconducting transmission. According to EPRI Senior Scientist Mario Rabinowitz, this could lead to the first economical superconducting underground transmission line.

At the present time, conventional underground transmission lines cost 5–15 times more than overhead lines. With this new superconductor, the cost could be reduced by half. "By the turn of the century, utilities may have the potential for transmitting more power with very low losses," reports Rabinowitz. "For direct current, there would no longer be resistance to the flow of electricity. For alternating current, there would be a miniscule power loss."

The new tape can carry current at 10,000 times the current density of copper or aluminum, which are used as conductors by the utility industry today.

The development program, aimed at producing superconductors that operate at temperatures above 12 K for power transmission, has been sponsored by EPRI since July 1975. The LASL project has been a leader in the development of the niobium-germanium superconductor. The significance of the present achievement is that a major step has been taken—from small-sample, laboratory-scale material (less than 25 millimeters) to the production-line fabrication of conductors.

To date, the LASL group has demonstrated the continuous coating of niobium-germanium onto moving tapes of 20-meter lengths. Scaling up to longer lengths suitable for commercial production should not present any significant problems, reports Rabinowitz.

Sludge Treatment Guidelines

Efforts by the electric utilities to reduce pollution from power plant gaseous emissions have resulted in another environmental problem—sludge, the solid waste that is left behind.

Utilities produced 2.5 million tons of sludge last year, and it is estimated that by 1985 the total production could reach 60,000 acre-feet a year. That is enough to cover 90 square miles of land area 1 foot deep.

What are the utilities going to do with it?

A report recently released by EPRI evaluates sludge treatment methods and elaborates on the various conditions that would make specific techniques environmentally and economically acceptable for use (*State of the Art of FGD Sludge Fixation,* EPRI FP-671).

The report also reviews the results of evaluation tests performed on treated sludge to identify how successful specific techniques are in producing a chemically and physically stable product to aid utilities in selecting appropriate treatment at specific plants.

Some sludge treatment processes convert the sludge into cementlike compounds that bind the individual sludge particles together, improving the structural strength of the material and reducing its leachability, says EPRI Project

Manager Thomas Morasky. Once processed, the sludge is acceptable for landfill.

These processes are particularly attractive to utilities that have been using sludge ponds to dispose of their sludge. Pond disposal is not always satisfactory because some sludge can reliquefy after processing (dewatering) and special pond construction may be needed to prevent the leaching of contaminants into the groundwater, according to Morasky.

The report, the first of four on sludge disposal to be completed by EPRI contractors, summarizes sludge treatment processes and their uses at specific power plants, such as the Bruce Mansfield Plant in Shippingport, Pennsylvania, and the Conesville Station in Conesville, Ohio. The report, prepared by Michael Baker, Jr., Inc., Consulting Engineers of Beaver, Pennsylvania, also summarizes a method developed to estimate how much it would cost utilities to treat various types of sludge. The method can be applied to specific power stations to estimate their total sludge disposal costs.

Fuel Cell Power Plants Studied

The blueprint for a new power plant that, unlike all other fossil-fired plants, would produce electricity without combustion is being developed by General Electric Co. for EPRI.

The power plant will use second-generation fuel cells—batterylike devices that employ a molten salt electrolyte to convert the chemical energy in coal or oil directly into electricity. (First-generation fuel cells, which use an acid-based electrolyte, will be demonstrated next year under a separate EPRI–DOE program.)

The EPRI-sponsored project complements a parallel project by General

EPRI Negotiates 35 Contracts

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
Fossil Fuel and Advanced Systems Division				
RP377-4	Brayton-Cycle Solar Electric Pilot Plant: System Analysis and Definition	7 months	99.8	Boeing Engineering & Construction *J. Bigger*
RP981-1	Aqueous Carbonate Flue Gas Desulfurization Process Development	11 months	298.4	Atomics International *S. Dalton*
RP986-4	Coolwater Coal Gasification Study—Phase II	8 months	140.3	Southern California Edison Co. *M. Gluckman*
RP991-1	Penetration Analysis of Advanced Coal Power Generation Systems	16 months	99.0	Power Technologies, Inc. *O. Gildersleeve*
RP1041-3	Evaluation of Alloys for Fuel Cell Heat Exchangers	8 months	56.3	Lockheed Missiles & Space Co., Inc. *J. Stringer*
RP1129-1	Design and Fabrication of a Fabric Filter Test Module	6 months	160.6	Kaiser Engineers *R. Carr*
RP1132-1	Biofouling Control Practice and Assessment	1 year	212.1	NUS Corporation *R. Jorden*
RP1198-2	Capital Costs of Advanced Batteries for Utility Energy Storage	1 year	60.0	Arthur D. Little, Inc. *J. Birk*
RP1226-3	Advanced Rotor Forging Procurement	11 months	26.0	Engineering Materials & Processes, Inc. *R. Jaffee*
RP1257-1	Laboratory Testing—RESOX	9 months	141.9	Foster Wheeler Energy Corp. *S. Dalton*
RP1266-1	Influence of Texture and Microstructure on Properties of Ti-6Al-4V as Low-Pressure Turbine Blading Material	2 years	50.9	Institut fuer Werkstoffe *K. Kinsman*
Nuclear Power Division				
S125-1	Magnetic Flux Leakage for Measurement of Crevice Gap Clearance and Tube Support Plate Inspection	13 months	87.7	Colorado State University *J. Mundis*
RP452-2	Modification of the Fission Product Buildup Program EPRI–CINDER to Interface With Fuel Cycle Analysis Code ARMP	6 months	19.9	Science Applications, Inc. *O. Ozer*
RP964-5	Nonlinear Finite Element Piping Code Development in Support of Indian Point I Tests	3 months	18.0	H. D. Hibbitt & Associates, Inc. *C. Chan*
RP1021-2	Irradiation of Thermal Anneal Specimens	26 months	255.2	University of Virginia *T. Marston*
RP1119-2	Analysis of the Peach Bottom Transient Tests	16 months	24.2	Scandpower Inc. *J. Naser*
RP1124-1	Turbine Chemical Monitoring—Project Management Assistance	22 months	64.1	NUS Corporation *T. Passell*

Electric Co., for DOE. In the DOE program, scientists at General Electric's Research and Development Center will develop the technology for the second-generation fuel cell, which will offer the advantages of higher efficiency and the ability to use a variety of fuels, including those derived from coal. However, it could take a decade or more to develop the second-generation fuel cell for commercial use.

Success in the early phases of these two research efforts could lead to the construction and testing of a multimegawatt demonstration fuel cell power plant in the late 1980s, reports Arnold Fickett, manager of the Fuel Cells and Chemical Energy Conversion Program at EPRI.

The second-generation fuel cell system is expected to be 75% more efficient than conventional combustion turbines, Fickett says. It will produce electricity quietly, with few moving parts and with fewer pollutants than other commercial power plants.

An inherent advantage of fuel cell power plants is that they can be built as modular units. Generating capacity can thus be added as required. There will probably be only a small variation in the cost per unit of electricity output between the smallest and the largest fuel cell power plants. This feature, coupled with the likelihood of low environmental impact, makes fuel cells potentially attractive for substation-type power plants that are designed to meet the electric needs of a neighborhood or small community. The size of the fuel cell power plants could be increased as a community grows.

Although molten salt fuel cell systems hold long-range promise for clean, efficient power production, there remain unsolved problems involving the fabrication and performance of cell electrolytes and the corrosion of seals and other structural components.

"If these and other technical problems are overcome," Fickett says, "second-generation fuel cells could have a high potential for future coal-based power generation."

Number	*Title*	*Duration*	*Funding ($000)*	*Contractor/ EPRI Project Manager*
RP1128-1	Technical Feasibility of Low Water Volume Fraction Lattice Reactor Designs	1 year	16.1	Virginia Polytechnic Institute *R. Sehgal*
RP1168-1	Monitoring Techniques for pH, Hydrogen, and Redox Potential	2 years	201.5	SRI International *T. Passell*
RP1238-1	Analytic Functions for Tearing Modulus Determination	1 year	75.1	Washington University *T. Marston*
RP1241-1	Feedwater Nozzle Instability Analysis	7 months	48.6	Washington University *T. Marston*
Electrical Systems Division				
RP1048-2	Determination of Three-Sample Dynamic Models	2 years	177.0	Power Technologies, Inc. *C. Frank*
RP1095-6	Galloping Control by Detuning	27 months	24.6	Alcoa Conductor Products Co. *M. Silva*
RP1144-1	Determination of the Cause, Mechanism, and Mitigation of URD Concentric Neutral Corrosion	3 years	233.7	Florida Power & Light Co. *B. Shula*
RP1202-1	Phase-to-Phase Switching Surge Strength	13 months	272.5	Power Technologies, Inc. *E. Ballard*
RP1209-1	Distribution Fault Current Analysis	38 months	806.9	Power Technologies, Inc. *H. Songster*
RP1210-1	Crystallized Fly Ash Feasibility Study	18 months	161.7	ECP Inc. *R. Tackaberry*
RP1270-1	Gas Turbine Modification and Testing for Solar-Fossil Hybrid Operation	4 months	19.7	Solar Turbines International *J. Bigger*
RP1285-1	Detection of High Impedance Faults on Distribution Circuits	2 years	397.6	Power Technologies, Inc. *H. Songster*
RP7869-1	Development of a Leak Location System for Use on Underground Electric Power Transmission Cable	2 years	349.0	Power Technologies, Inc. *T. Rodenbaugh*
Energy Analysis and Environment Division				
RP1104-1	Economic and Social Costs of Energy and Capacity Shortages	1 year	99.4	Jack Faucett Associates, Inc. *A. Halter*
RP1114-1	Environmental Impacts of Dispersed and Concentrated Coal-Burning Power Plants	1 year	90.0	General Electric Co. Center for Advanced Studies *R. Wyzga*
RP1114-2	Environmental Impacts of Dispersed and Concentrated Coal-Burning Power Plants	1 year	30.0	Mathtech, Inc. *R. Wyzga*
RP1216-1	Energy Use and Electricity Demand of Commerical Buildings	18 months	228.5	Hittman Associates, Inc. *A. Lawrence*
RP1312-1	Ecological Effects of Chlorine Use for Biofouling Control	8 months	48.7	Academy of Natural Sciences of Philadelphia *R. Kawaratani*

Washington Report

Coal Liquefaction in the Limelight at DOE

□ Plans are under way at DOE to build two commercial-size modules (6000 t/d) that will produce clean fuels from coal by the solvent refined coal (SRC) process. One will produce a solid fuel (SRC-I); the other, a liquid fuel (SRC-II). Backup will be provided by the SRC pilot plants in Tacoma, Washington (30–50 t/d), and Wilsonville, Alabama (5 t/d).

□ Ground will be broken this month in Baytown, Texas, for a 250-t/d pilot plant designed to make clean liquid fuels from coal by the Exxon Donor Solvent (EDS) method.

□ Construction is continuing and operation should begin later this year in Cattletsburg, Kentucky, at a 200–600-t/d pilot plant that will also convert coal to liquids, using a process known as H-Coal.

The trio of technologies being developed in these facilities is the core of the federal coal liquefaction program, an energy technology R&D effort that is often in the limelight these days. Major initiatives are being taken in this area, and a general feeling seems to have developed in Congress, at DOE, and within private industry that acceleration of these efforts is timely and appropriate.

The electric utility industry has a particular interest in coal liquefaction R&D efforts because coal liquids may some day offer utilities alternative fuels for existing oil-powered facilities. The industry also projects that these liquids will be used to fire combustion turbine–combined-cycle power plants to help meet intermediate and peak electricity demand.

At the present time, however, technical and economic uncertainties remain, and the industry has been supporting R&D in the coal liquefaction area, both in cooperation with the federal government and through parallel efforts. EPRI, for example, is sharing the funding of the EDS project in Texas with DOE, Carter Oil Co., Phillips Petroleum, and Atlantic Richfield Corp. The Institute is also a cosponsor of the H-Coal project in Kentucky, along with DOE, the State of Kentucky, Ashland Oil Inc., Standard Oil of Indiana, Conoco, and Mobil Oil Corp. Although EPRI is not directly involved in the SRC project in Tacoma, Washington, the Institute is supporting a 5-t/d SRC facility in Wilsonville, Alabama, in conjunction with Southern Company Services, Inc. Results of tests carried out at this plant (which produces the solid form of SRC) have supplemented data obtained from the DOE plant at Tacoma.

Why is the federal government interested in developing coal liquids and why the push right now? George Fumich, a senior DOE official in this area, explains it as a function of a "new pattern of priorities evolving within DOE, a pattern that will have a particularly profound effect on development and use of coal, the nation's most abundant fossil fuel."

In the past, Fumich explained, federal emphasis on developing new types of energy sources was on creating technical options for the future. "But with the need to stem increased dependence on imported oil, the nation can ill afford to have new technologies remain on the laboratory shelf, untried in the commercial sector. Today's focus must be on true commercial application of technologies, rather than just technical readiness."

Energy Secretary James Schlesinger echoed these sentiments in testimony April 3 before a subcommittee of the House Appropriations Committee.

"At the present time, the Department is in the process of developing a series of supply initiatives to readjust priorities in areas that the administration believes will be of critical importance in reaching energy supply goals over the next decade . . ." he said. "Our shared goal is a simple one—to ensure that a full range of supply options capable of making a meaningful contribution to total U.S. energy supply by the mid-to-late 1980s is available." Initiatives in the areas of coal liquefaction commercialization were among those mentioned by Schlesinger as possible options for inclusion in this package.

DOE inherited the federal coal liquefaction program from ERDA, which in turn had received it from the office of Coal Research in the Interior Department. Within DOE, the program has been assigned to the jurisdiction of the Assistant Secretary for Energy Technology.

Within the general umbrella of Energy Technology, liquefaction falls under the Division of Coal Conversion, which is part of the Office of Fossil Energy. Fumich, who is acting director of that office, explains that the fundamental strategy of his overall fossil program is "to develop technologies that will permit a smooth transition to the widespread use of plentiful fossil fuels in lieu of scarcer and more expensive resources."

In budget terms, this translates into heavy emphasis on coal, the resource that makes up 90% of U.S. fossil reserves. Of the total $742.9 million in budget authority allocated for fossil energy in 1978, $579.1 million is going to the coal program. (Other programs include petroleum, gas, and improved conversion efficiency.) Liquefaction efforts are receiving $110.6 million of that figure. For FY79, DOE has requested $801.8 million for fossil energy, $618.2 million for coal, and $125.1 million for liquefaction.

Fumich is optimistic about the future of the coal liquids efforts. "If we push hard enough," he says, "I firmly believe that we can have the beginnings of a coal liquids industry by 1985. We're not going to have a large input of synthetic fuel by that time, but if we can get a reasonable effort started by 1985, in my estimation coal liquids can be a major force in the country by 1990."

Fumich points to the broad range of applications that the federal government envisions for coal liquids. He explains that initially they may be used in power plants and industry boilers, and later upgraded and refined for use in the transportation sector. However, he stops far short of saying that coal liquids could replace oil. "We're going to be relying on Mr. Oil for a long time to come," he says. Coal liquids are seen as a supplement to oil, not as a substitute.

An integral concept underlying the federal coal liquefaction effort is the importance of private industry involvement.

"What we're trying to do is develop a technology that's going to be used by private industry, so at some point during the development process, private industry has to be involved," Fumich states. He describes the timing of cooperative funding as "taxpayer dollars on the front side; then a mixture of taxpayer dollars and private industry money; and finally, all private dollars."

Fumich remarks that DOE and EPRI cooperation on coal liquefaction projects has synergistic effects. He explains the relationship as "good for you in that you're going to get some public money in the areas you're interested in for your industry, and good for us in that we're not developing a white elephant."

In addition to the three main coal liquefaction processes being developed (SRC, EDS, and H-Coal), the federal program also includes R&D on some technologies in the very early stages of development; some materials research; support of a liquefaction test facility in Cresap, West Virginia; and some partial support of the Wilsonville SRC facility.

Fumich explains that DOE's strategy is to support a number of liquefaction processes in parallel from laboratory scale through process development units to pilot plant stage. The approach is based on a number of considerations. "The variety of coals to be processed, coupled with the requirements for a wide range of fuels, will necessitate commercialization of a number of liquefaction processes," he says. "The final objective is to demonstrate at near-commercial scale those selected second-generation synthetic fuel conversion processes that have been developed and evaluated through industry and government R&D."

Exactly when that demonstration will take place and precisely which candidate processes will make it that far are policy questions that are currently under consideration. At the present time, all are still in the running and DOE continues to work in conjunction with private industry to develop a liquefaction technology capable of helping the country through the energy transition period it faces in the near future.

R&D Status Report
FOSSIL FUEL AND ADVANCED SYSTEMS DIVISION

Richard E. Balzhiser, Director

WATER-COOLED GAS TURBINE DEVELOPMENT

The emphasis of this project in combustion turbines has been modified to accentuate the obtaining of low metal temperatures rather than high gas temperatures. Metal temperatures below 550°C (1000°F) should be able to provide freedom from corrosion with even the lowest-quality liquid fuels. This feature will provide increased reliability and enhanced ability to burn a broad range of liquid fuels. There still will be fuel limitation due to ash deposition and emission regulations. The growth capability to much higher gas temperatures is still inherent in the cooling scheme. This will tend to lower the heat rate and the dollars per kilowatt (*EPRI Journal,* March 1976, p. 26).

This project is coordinated with DOE's high-temperature turbine technology (HTTT) program, which has provided an overall design and parts fabrication development for the water-cooled turbine. However, as the HTTT project has become concentrated on low-Btu gas fuels, there is now a divergence in purpose of the projects.

In the water-cooled turbine design, water is fed on to the turbine wheel into the supply reservoir (Figure 1). Centrifugal force sends it up the shank supply channels into the flow control assembly where it is metered to the many coolant tubes located under the blade skin. The water flows up the coolant tubes removing the heat transferred to the blades by the hot gas stream. It is expected that approximately two-thirds of the water will be boiled to steam. The water, steam, or mixture then exits at the blade tip where the steam mixes with the hot gas stream, while the water is planned to be collected in the stationary shroud water collection chamber.

The blade design consists of an internal spar that mainly carries the blade stress. Stainless steel is the current design choice for this spar. The spar is covered by a copper lining in which the coolant tubes are inserted. The copper lining, which can be plating or compressed powder, is used for its high heat transfer coefficient, which helps minimize thermal gradients. The coolant tubes are of steel or Monel alloy that is resistant to water erosion. Outside the copper lining is the skin, which is made of nickel superalloy chosen for its erosion and corrosion resistance to hot combustion products. Progress has been made in determining water side heat transfer rates and in developing internal coolant tube shapes that promote heat transfer to the values required to keep surface temperatures below 550°C (1000°F). This work has been done

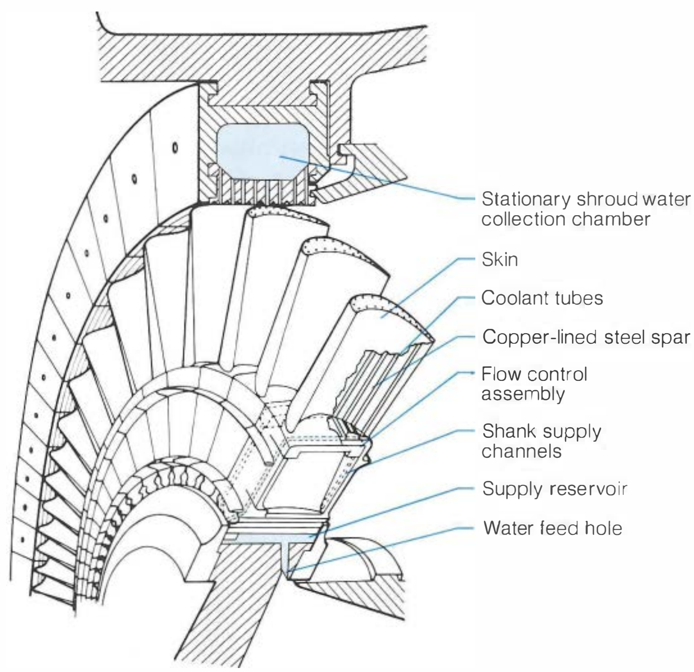


Figure 1 Cross section of the water-cooled gas turbine, revealing the coolant tubes and water collection system.

in a motorized test rig that consists of an electric-motor-driven spinning metal slat with Calrod heaters surrounding the coolant tubes at both ends of the slat. This rig has also demonstrated negligible water erosion, deposition, and corrosion inside the coolant tubes for straight channel section tubes. The present design configuration uses crimped tubes to promote surface wetting, but no long-term tests have yet been performed on this configuration.

An approximately one-fifth-scale turbine stage rig has been built and run. This has demonstrated metal temperatures below 550°C (1000°F) in operation at up to 1650°C (3000°F) gas temperature. Virtually 100% water delivery to the rotating blades has been obtained in these tests. Very high water collection efficiency has also been obtained at low pressure ratios across the stage. However, efficient water collection is still a major problem at the design stage pressure ratio, and it may not be possible to collect the liquid stream leaving the turbine blades. Water collection is important for diminishing water consumption and for preventing erosion of downstream stages by any water droplets in the flow. The water collected can be injected into the combustor to suppress NO_x formation or used for feedwater heating in a combined cycle.

A full-scale, 2.4-m-diam (8-ft-diam) wheelbox, simulated water-cooled turbine rotor has been constructed and has completed preliminary checkout tests (Figure 2). This rig has the objective of proof-testing, in full scale, water delivery and collection, water flow effects on dynamic balancing, and heat transfer rates at the full Coriolus and centrifugal fields that are only obtainable in this rig. The wheelbox is electric-motor-driven, so there is no hot gas flow. The blades of this rig are aerodynamically simplified to reduce drag. Four special blades (one of which is shown in Figure 2) contain Calrod heaters that will demonstrate coolant tube heat transfer rate at full scale, full rotational forces, and full design heat fluxes. The wheel and all the blades contain water feed and simulated coolant tubes, while the stationary housing contains water collection ducts. The wheelbox, along with the scaled turbine stage, should assist in the development of an efficient water collection design.

In addition to this hardware, an innovation of this project that provides a great deal of information at a low dollar expenditure is the building of clear plastic rigs. While these rigs are incapable of running hot, they provide important visual information on the water transfer and flow properties that guide analytic understanding and design. One plastic rig models the flow control assembly section, where water is metered into individual blade coolant tubes from the two main water supply channels in the blade shank. The water dynamics that were observed showed potential instability ranges and guided the design out of these ranges. Another rig, consisting of a motor-spun clear plastic pipe, allows visual assessment of the combined effects of Coriolis force, centrifugal force, and surface tension on the wetted area of the cooling-water flow.

Clear plastic has also been used to construct a temporary water-collection stationary shroud for the scaled turbine rig. During cold air flow operation, the flow properties of the water exiting from the blades were observed and the shroud modified for the most efficient water collection. The metal collection shroud duplicated this design. Unfortunately, however, the use of this procedure was impossible during pressurized operation. A new clear plastic water collection rig is being designed that will allow flow observation during pressurized operation and is designed for facile stationary shroud geometry variations. This rig will greatly assist in solving the water collection problem.

A rig consisting of a small, high-temperature combustor followed by a multistation test section (minirig) has recently started operation. The minirig combustor is lined with SiC ceramic to allow combustion exit temperatures from 800°C (1500°F) to

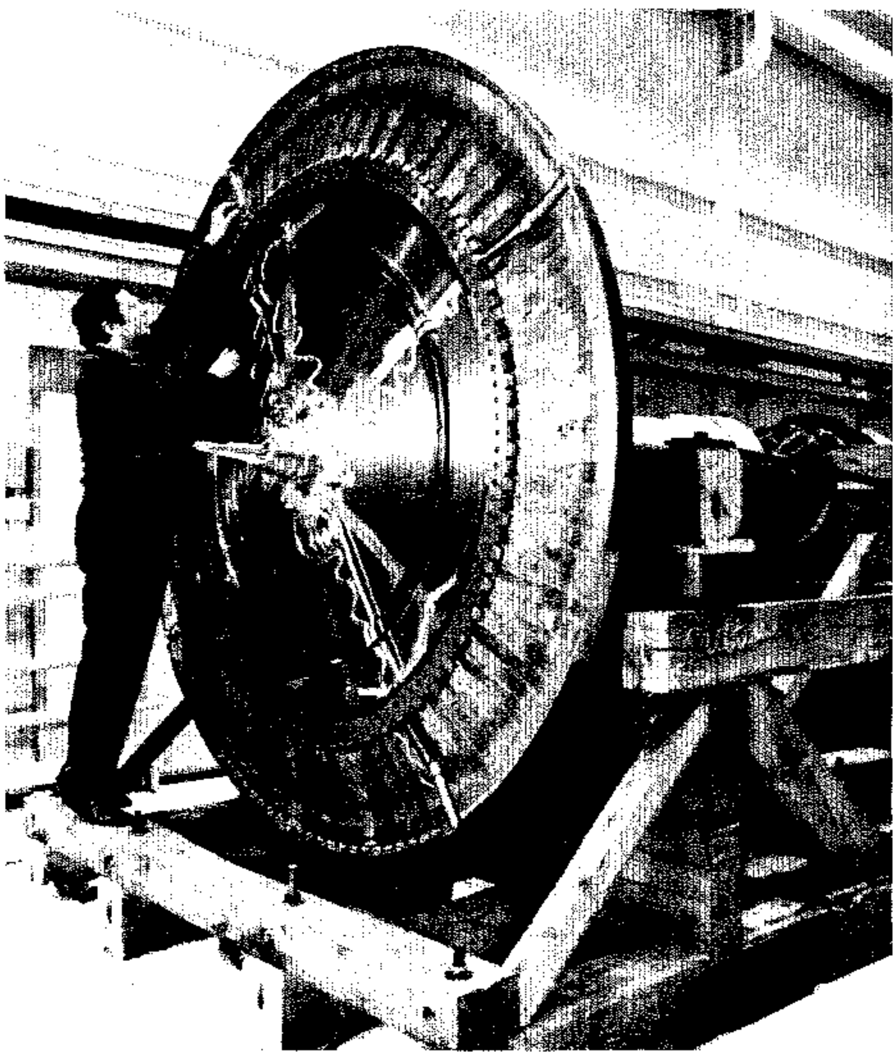


Figure 2 Full-scale wheelbox stage rig, with one of the four special heated blades indicated.

1650°C (3000°F). This combustor liner was developed earlier in the program. There are nine test stations in which, simultaneously, water-cooled hollow pins of various alloys and surface temperatures can be tested to determine corrosion effects. Mainly No. 2 distillate fuel, doped to simulate coal liquids and residual oil combustion impurities, will be burned. However, a short test will also be run on low-Btu gas from the GEGAS gasifier now in operation. These data probably could not be easily obtained at a later time, as the gasifier is expected to be taken out of service. While gas fuel is not the current emphasis, it provides insurance for any change. The purpose of this rig is to verify the very low corrosion rates (indicated by earlier pot furnace testing) at the low surface temperatures provided by the water cooling.

Work is progressing on improved blade fabrication procedures. The problem is how to include the coolant tubes and the heat-conductive copper lining in the blades. With the emphasis now on aiming for lower gas temperatures (1150–1250°C [2100–2300°F]), this design is much more straightforward, as the amount of copper required is reduced. Copper can be eliminated from some components while thin copper plating, rather than thick powder, can be used to make the lining on others.

The development of fabrication techniques and the determination of an efficient water collection design are the two main problems that are now seen as barriers to a positive feasibility assessment. The work currently being focused on these areas should lead to the elimination of those barriers. *Project Manager: Arthur Cohn*

GEOTHERMAL PROGRAM

Development of hydrothermal (hot water) resources continues to receive high priority, with the main focus on the geothermal demonstration plant at Heber, California, and supporting projects. With near-term objectives established for these projects, hardware development is being planned to improve performance in the next generation of hydrothermal power plants. The geopressure subprogram has been elevated in priority and its schedule moved up. A requirements definition and impact analysis study of geopressure is due to begin. Significant progress has also been made in the brine chemistry projects.

In industry, the level of activity in hydrothermal development has increased during the past year. Activities include tentative plans to build power plants at the following sites in California between 1980 and 1982:

Heber	45 MW (e) Binary cycle
	50 MW (e) Flashed steam
East Mesa	50 MW (e) Flashed steam
	11.2 MW (e) Binary cycle
North Brawley	10 MW (e)
Niland	10 MW (e)

Outside California, plans include a 50-MW(e) plant at Valles Caldera in New Mexico and a 50-MW (e) plant at Roosevelt Hot Springs in Utah, also by the end of 1982. The EPRI effort is a key part of these initial plans to use hydrothermal resources for power generation.

The flashed-steam process and the binary cycle represent the current technology for generating electric power with hydrothermal resources. Both technologies use brine as the source of heat. In a flashed-steam plant, hot brine is subjected to a rapid decrease in pressure. Steam flashes from the brine, is separated from it, and is used to drive a steam turbine. In contrast, the binary cycle isolates the turbine from the brine. The brine heats a working fluid in a heat exchanger and produces a vapor. The vapor drives a turbine. Vapor exhausting from the turbine is condensed and pumped back to the heat exchanger.

Steam turbines and the flashed-steam process will be used to develop resources that have high brine temperatures, low mineral content in flashed steam, low noncondensible gas content in steam, and generally low mineral content in the brine. Binary-cycle plants have better efficiency at lower brine temperatures or with brines having high noncondensible gas contents. Use of the binary cycle limits the corrosion and scaling impacts of the brine to the brine–working fluid heat exchangers.

Heber demonstration plant

Engineering design of the binary-cycle plant at Heber was initiated with the San Diego Gas and Electric Co. (SDG&E) in June 1977 (RP580-2). Preparation of the environmental impact report was started at the same time, and the draft is now complete. In addition to the technical efforts, agreements were completed by SDG&E on energy purchase, power sales, water supply, owner participation, and nonowner participation. The participants in the project include: San Diego Gas and Electric Co., Electric Power Research Institute, Imperial Irrigation District, Los Angeles Department of Water and Power, Southern California Edison Co., California Energy Resources Conservation and Development Commission, Nevada Power Co., Portland General Electric Co., and Republic Geothermal, Inc.

The owner participants have submitted a proposal to DOE to provide funding support to the project, in response to DOE's Program Opportunity Notice issued in September 1977. DOE is expected to reach a decision on its selection late in May. *Program Manager: Vasel Roberts*

Geopressure subprogram

An EPRI subprogram will address the technical and economic issues of geopressured resources, which are generally found in deep, sedimentary basins and have been encountered on- and offshore of the U.S. Gulf Coast. Estimates of the geopressured resource potential range from little or none to very high. The most optimistic estimates place the methane content at considerably greater than total U.S. domestic reserves of natural gas. Prospects for recovery of these resources are as uncertain as the estimates of quantity.

The first geopressure project will concentrate on two areas (RP1272). It will establish whether the geopressured resource offers sufficient promise to warrant aggressive electric utility industry research. Also, EPRI will determine the requirements for brine handling and electric generation equipment processes and other R&D needs. This activity will identify not only existing geothermal technology that is transferable to the geopressured resource but also new technology required to exploit the resource.

Identified resource areas include approximately 75 prospective reservoirs in Texas and Louisiana. It is likely that one or more geopressured reservoirs will be drilled by others during the period of performance of RP1272. Thus, some of the first key data on reservoir brine composition, permeability and porosity, methane content, and well production are expected to become available during this period. *Program Manager: Vasel Roberts*

Hydrocarbon turbine studies

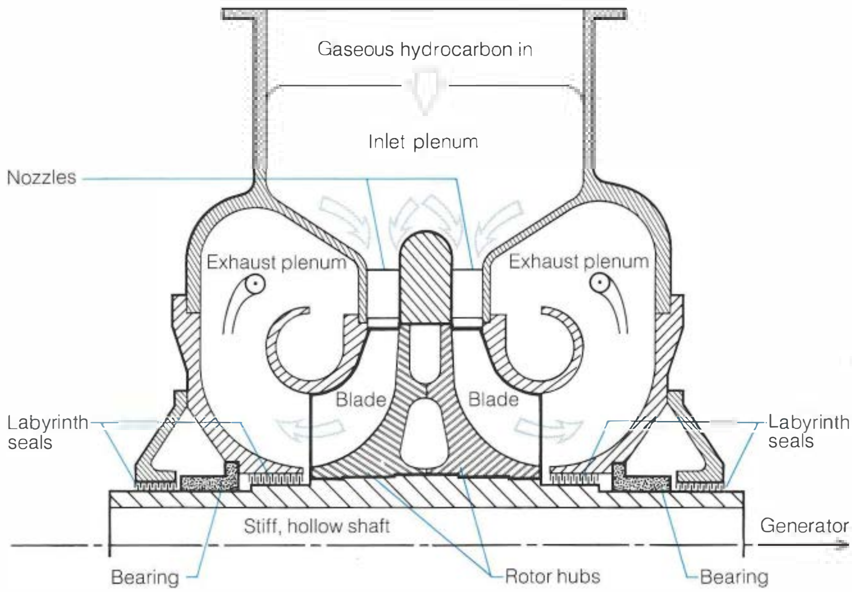
Two candidate concepts for binary-cycle hydrocarbon turbines are the axial-flow and radial-flow machines. The axial-flow machine is constructed similarly to familiar utility steam turbines. The radial-flow machine extracts energy from the working fluid (hydrocarbon) vapor, while the vapor flows radially inward and axially outward along a bladed wheel. EPRI funded The Elliott

Co. (RP928-1) and the Rotoflow Corp. (RP928-3) to perform conceptual design studies of these two hydrocarbon turbine concepts. Progress on the axial-flow study was reported in the *EPRI Journal*, August 1977, p. 53.

Rotoflow Corp. has completed a conceptual design for a 65-MW (e) radial-inflow hydrocarbon turbine generator. A double-entry design with two wheels placed back-to-back (Figure 3) uses 1270-mm (50-in) cast-aluminum wheels, which rotate at 3600 rpm. Control is achieved by using rings of nozzles equally spaced about the circumference of each wheel. A single nozzle-control mechanism actuates all the nozzles simultaneously and is activated in turn from a governor system similar to steam turbine practice. Primary emergency shutdown is achieved using the nozzles; final shutdown is achieved using an off-the-shelf stop valve similar to steam turbine practice.

The shaft of the radial-inflow turbine is a hollow, stiff design, with the fundamental vibrational mode above the operating speed (critical speed margin is 50%). Labyrinth seals operating with seal gas prevent escape of hydrocarbons. Inlet line sizes of up to 720 mm (30 in) and exhaust line sizes of up to 1750 mm (72 in) per wheel are required. Casing size for two wheels is approximately 2540 mm (100 in) in diameter and 2030 mm (80 in) long. Separate seal and lube oil systems for the turbine and the generator prevent intermixing of the hydrogen generator coolant with the hydrocarbon secondary working fluid.

Figure 3 Cross-section view of radial-inflow expander. This machine is a single-entry double-flow stiff-shaft design.



Consistent with the present view of the Heber demonstration plant conditions, the two-part hydrocarbon (80% isobutane with 20% isopentane) enters the turbine at 149°C and 3520 kPa (300°F, 510 psia). The working fluid, which exits at 63°C and 365 kPa (146°F, 53 psia), flows at the rate of 66.3 kg/kWh (147 lb/kWh). Turbine efficiency is 86%. Plant heat rate for 182°C (360°F) brine, using the above power conversion system, would be about 30,000 Btu/kWh. *Project Manager: Gary Underhill*

Hydrocarbon working fluid properties

Design of binary-cycle power plants depends on knowledge of working fluid properties and on knowledge of heat transfer to these working fluids at elevated temperatures. EPRI has implemented projects to improve data on fluid properties and on heat transfer for selected hydrocarbon working fluids.

Available data on thermodynamic properties and transport properties (viscosity and thermal conductivity) of candidate hydrocarbon working fluids rest, in most cases, on fluid thermodynamic and transport properties correlations, including enthalpy, density, specific heat, viscosity, and thermal conductivity as a function of pressure, temperature, and quality, derived from relatively meager experimental data. Data requirements in the petroleum and petrochemical industries have been for open-ended processes. For power generation plants using binary cycles, closed-cycle loops are required, in which the available energy for conversion is a small percentage of the total energy transferred to and rejected from the loop. Hence, the effect of errors in thermodynamic and transport properties can be significant.

RP928-4 concerns the measurement of enthalpy as a function of temperature and pressure for isobutane and for a mixture of 20% isopentane in isobutane. Properties for the mixture were determined at 200 state points over the ranges of temperature from 42°C (110°F) to 165°C (325°F) and of pressure from 552 kPa (80 psia) to 4137 kPa (600 psia). For isobutane, enthalpy was determined at 47 state points along the 1724 kPa (250 psia) isobar over the temperature range of 77°C (170°F) to 121°C (250°F) for comparison with some existing pure component data. Figure 4 presents the isobutane data as a plot of enthalpy and a function of temperature. It is clear that these data represent a lesser degree of refinement than data on current thermodynamic properties of steam. *Project Manager: Gary Underhill*

Binary-loop test

The thermodynamic and transport data from RP928-4 and RP1195 will make an important contribution to the interpretation of results for a binary-loop test (RP1094), cooperatively funded by EPRI and DOE. This project is an experimental investigation of supercritical hydrocarbon heat transfer, scale deposition from brine to heat transfer surface along the brine path in hydrocarbon vaporizers, materials performance in the brine path of vaporizers, and the effect of chemical backwash (for scale removal) on the brine path materials in vaporizers. The tests will be conducted at Heber, California, by the contractors, one of which is C. F. Braun Co. (RP928-4). Two results are anticipated from this work: practical guidelines for design and operation of supercritical binary-cycle power conversion loops; and benchmark data with which to compare analytic and numeric design methods. *Project Manager: Gary Underhill*

Brine chemistry

The primary objective of the brine-chemistry, combined heat transfer project at Battelle, Pacific Northwest Laboratories is to develop the analytic capability to simulate scale formation in geothermal brine systems (RP653-1). The product will be a set of computer programs that can be used to analyze the chemistry, chemical kinetics, scale deposition, and corrosion in such systems. The computer program set will have four major subprograms, including equilibrium brine chemistry, scaling kinetics, corrosion, and hydrodynamics and thermodynamics simulation.

Completion of the basic equilibrium chemistry computer program was reported in the August 1977 *EPRI Journal*. Since that time, the program has been expanded to include additional important chemical and mineral species, such as antimony and zinc. The first draft of the user's manual for this computer subprogram has been completed. The potential usefulness of the program is illustrated by an analysis of the chemical kinetics in the M-39 geothermal well at Cerro Prieto, Mexico, and comparison of EPRI results with observed performance and scaling. Experience shows plugging of the well within three months due to calcite scale deposition. EPRI analysis of the amount of scale formation agrees with field measurements and suggests that if the well operating temperature were raised 8°C, most of the scaling in the well might be prevented. The well has not yet been tested at the new condition, but if it is, it will be a valuable test of the equilibrium application of the chemistry model to field conditions.

Brine chemical reactions with rock formations and their kinetics are especially important to geothermal fluid reinjection, which is expected to be widely used for fluid disposal. The temperature and pressure at which waste geothermal brines are reinjected are significantly lower than those at which the brine was produced. Therefore, the reinjected brines will not be in chemical equilibrium with the rock formation in the reservoir. Chemical reactions resulting from the disequilibrium could cause either an increase or a decrease in the feasibility of injecting the brine into the rock.

Stanford University is experimentally investigating the reaction chemistry between brine solutions and rocks and their chemical kinetics (RP653-2). The experiments involve mixing geothermal brine and rock together in a nonreactive chamber at temperatures and pressures found in natural geothermal systems. The nonreactive cell is designed to allow incremental removal of small quantities of geothermal brine for chemical analysis as a function of time without disturbing the experimental conditions. Chemical analysis of the fluid provides data on rock-brine reactions and their kinetics. Preliminary results indicate the significance of these data to the geothermal engineer.

For example, one set of experiments showed that rapid changes occur in chemical concentrations over very short time intervals, producing apparent supersaturation of many chemical species before they reach equilibrium concentrations. This implies a potential for solution of rock material in the formation of reinjection well walls with potential for precipitation and plugging after the fluid flows further into the formation. Experiments on basalt rock have indicated that H_2S and CO_2 can be produced in sufficient quantities from these rock-brine reactions to easily account for natural concentration levels. *Project Manager: Phillip La Mori*

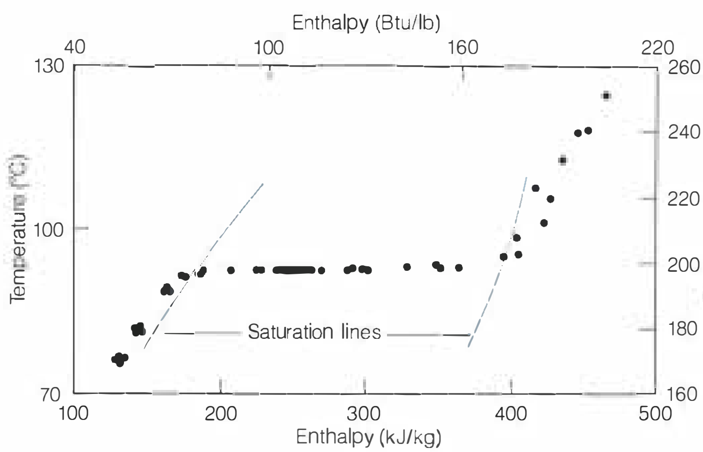


Figure 4 Experimental enthalpy of 99.6% pure isobutane for the 1.72 MPa (250 psia) isobar. The data in the two-phase region are of better quality than those in the superheated vapor and the subcooled liquid regions. These data are of significantly lower quality than the current data for water. The solid line is a compilation of the literature data. Enthalpy is zero for the saturated liquid at 24°C (75°F).

Heat rejection from geothermal power plants

The relatively low temperatures of geothermal resources result in thermal efficiencies of 10–15% in power conversion cycles. If conventional evaporative cooling methods are to be used, large quantities of cooling water will be required. R. W. Beck and Associates is evaluating approaches to water management in waste heat rejection options from geothermal power plants (RP927-1).

Progress in this project includes development of the analytic techniques, calculation of turbine performance curves for a range of condensing conditions for both the flashed-steam and hydrocarbon binary-cycle turbines, and initial analysis for a binary-cycle plant under desert-type climatic conditions. The California Energy Resources Conservation and Development Commission is supporting the project as a joint sponsor. *Project Manager: Phillip La Mori*

R&D Status Report
NUCLEAR POWER DIVISION

Milton Levenson, Director

REMOTE MULTIPLEXING FOR POWER PLANTS

During the last decade there has been a dramatic escalation in costs of plant construction, operation, and fuel, as well as a growing public concern about conservation. As a result, utilities are strongly committed to the improvement of plant performance. This firm commitment, the increasing size and complexity of power plants, the greater stringency of regulatory requirements, and the rapid advances in the electronics industry are all contributing to the introduction of new instrumentation and control technology.

Consequently, in a modern power-generating facility there are thousands of monitoring and control points that are individually hardwired between the field and the control building. Hardwiring requires that hundreds of miles of cable be strung, costing millions of dollars in materials and labor. Cable separation and fire protection requirements compound the complexity of plant wiring.

Recent advances in electronics make it possible to reduce instrumentation and control wiring through the use of remote multiplexing. Remote multiplexing systems (RMSs) are able to transmit many signals on a small number of wires. The individual field sensors and actuators are wired to remote terminals that are strategically distributed throughout the plant and sequentially sampled for transmissions by the remote multiplexers (Figure 1). In the control building, the signals are separated and distributed on short cables to their final destinations.

Remote multiplexing of signals to reduce wiring is a well-established technology in the military services and in the telephone and petroleum industries. A survey of RMS vendors shows that a diversity of commercially available systems exists. To date, however, utility experience with RMS power plant applications has been limited. But there is a growing interest—more than 41 utilities have indicated that they plan to implement some type of RMS. This may be attributed to the significant advantages that remote multiplexing appears to offer when compared with hardwiring.

- Cost savings and improved installation schedule
- Ease of modification and expansion
- Increased reliability through redundancy
- Less vulnerability to fire due to physical separation of redundant elements
- Simplified interfacing with plant instrumentation

In late 1975, EPRI initiated a 2½-year study to provide the utility industry with basic information for evaluating the use of

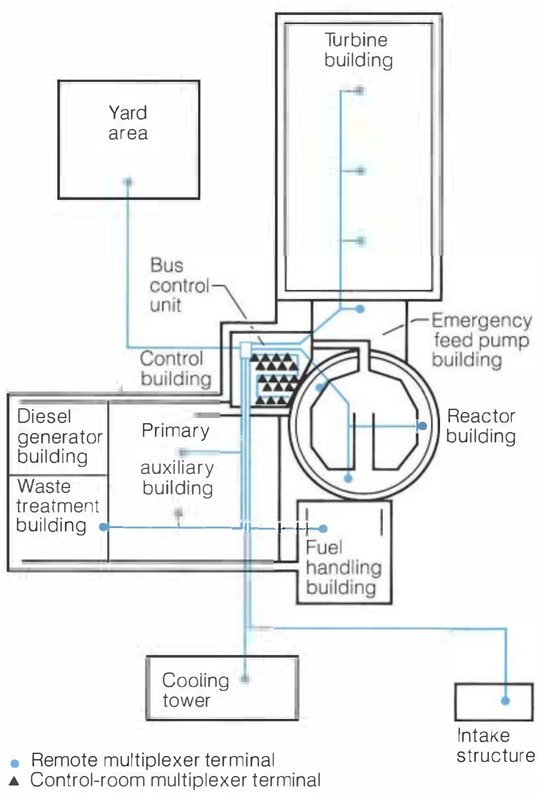


Figure 1 Typical multiplexing system installation, showing distribution of remote terminals throughout the plant.

RMSs in power plants, to develop guidelines that would help ensure that RMSs satisfy the desired functional requirements, and to identify potential problem areas needing additional R&D. The study was performed by TRW Systems and Energy Group and United Engineers and Constructors, Inc. The results have been published in three volumes with an executive summary (NP254) and are highlighted below.

The information to be transmitted on a hypothetical reference plant RMS was established on the basis of the signal and wiring requirements documented for five plants. The list included approximately 1500 safety and 3200 nonsafety instrumentation and control signals. In addition, 18 RMS functional guidelines were defined quantitatively, based on comments from a dozen utilities. These included a design life of 20 years, limited by the availability of parts; a requirement for central multiplexer control; a requirement for 30% spares; a definition of the amount of error protection required for each class of signal; and recommended levels of redundancy and fault-detection circuitry to achieve acceptable availability with reasonable maintenance policies. One safety and three nonsafety RMSs were defined and analyzed at the circuit board level. All four RMSs service the same reference plant, transmit instrumentation and control signals, interface to conventional control boards, and process computers.

The typical RMS has approximately 20 field terminals, 20 control building terminals, and a pair of redundant control units. The communication highway also contains redundancy and supports transmission rates close to one million bits of information per second. There is a growing interest in using fiber optics as the transmission medium because of advantages in noise immunity and isolation (RP1173).

For the reference plant studied, a plantwide nonsafety RMS is estimated to cost between $4 and $5 million. This assumes that the multiplexing system is a wire replacer and thus takes advantage of only a few plant design changes, which could further reduce costs and increase availability. Comparisons with hardwiring costs for the same plant revealed that

- Wiring labor and materials are $1.9 million cheaper for multiplexing systems
- Wiring-related savings with RMS are conservatively estimated at another $0.5 million
- Engineering, construction overhead, and interest constitute additional savings of $0.8 million for RMSs
- Multiplexer equipment, including applications engineering, will cost from $1.5 to $2.5 million
- Initial investment in a multiplexing system is thus expected to be from $1–$2 million less than that for conventional hardwiring
- Additional savings of 15–30% of RMS costs are possible in advanced cathode-ray-tube-based control rooms because of simplified interfaces
- The cost per incremental point with RMS is only 50–75% that of hardwiring

Cost comparisons between nonsafety multiplexers and hardwired systems depend on many factors, including plant size, design practices, and labor costs. Figure 2 shows how costs vary as the size of the reference plant is changed from 3200 field points to 8800 field points and as the average length of hardwired cables varies from 120 to 210 m (400 to 700 ft). Multiplexing reduces the cost of field labor by half as compared with hardwiring, while it doubles the cost of engineering labor. It is expected that electrician-labor costs will continue to rise, that no significant changes will occur in field wiring practices, and that technological advances in multiplexing will offset the rising cost of design, fabrication, and test labor. Therefore, wiring costs will rise faster than multiplexer costs, thus widening the gap between the two technologies and making multiplexing even more attractive in the future.

With the introduction of RMS for the transmission of important plant status and control information, it is possible that certain kinds of multiplexer failures might affect plant operations. To assess the magnitude of this problem, the reliability and availability of RMSs with different degrees of redundancy and different repair times were calculated, using component reliability data. Then different rules were established for the number of terminals or bus controllers that had to be simultaneously in a failed state before plant operating penalties were imposed. Ini-

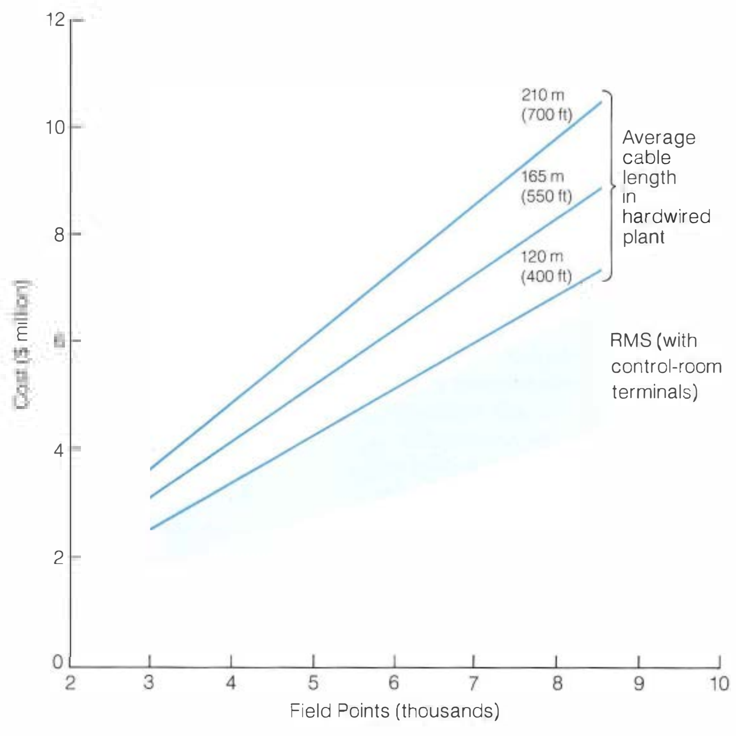


Figure 2 Estimated costs of a nonsafety multiplexing system and hardwiring for different numbers of field points and average cable length (based on an assumed electrician-labor rate of $14/hr). For the hardwiring case, the reference plant has an assumed average cable length of 165 m (550 ft).

tial hardware costs, maintenance charges, and operating penalties (in this case $500,000, assuming that the plant cannot return to service for 18 hours) were converted to present-value costs at 18% interest over the expected 20-year equipment life.

The results indicate that if the loss of any terminal affects plant operation, then a highly redundant self-checking system is more economical by tens of millions of dollars (Figure 3). In a more likely case, where loss of all points at several terminals can be tolerated without an operating penalty, a less expensive RMS with only redundant controllers and data highway is acceptable. A nonredundant RMS appears to be unsuitable for plantwide instrumentation and control applications. It should be noted that cable fires in nuclear plants have reduced plant availability by 1.3% (0.2%, if the Browns Ferry fire is excluded). The use of redundant RMSs would lessen the chance of similar losses in the future. A preliminary investigation of fourfold-redundant safety-system multiplexing was performed with a simplified version of a nonsafety RMS as the basis for each channel. The use of high-reliability parts, quality assurance, and system qualification programs was optimistically estimated to increase the entire system cost by not more than double.

The results suggest that the very high reliabilities representative of existing safety systems can also be achieved with RMS. However, present safety-system multiplexer costs are estimated to be 50% higher than conventional hardwiring costs. This difference may be reduced as the cost of cable separation and fire protection increases, and the initial expense of RMS qualification is defrayed over a number of installations.

It is anticipated that the increasing complexity of nuclear plants, the demand for improved availability, efficiency, and safety, and the need to comply with more stringent regulations will necessitate a greater reliance on more sophisticated instrumentation and control systems. The advent of reliable, powerful, but inexpensive electronic hardware and the continuing escalation of labor costs will further influence the utility industry to adopt such advanced technological systems as remote multiplexing.

The findings of this study indicate that remote multiplexing is technically feasible, can be designed to meet power plant availability requirements, can save millions of dollars as a replacer of conventional nonsafety hardwiring, and may provide other significant advantages. However, because of the many applications-dependent parameters, specific analyses should be performed for each installation. For this reason, the project has developed a general evaluation methodology and has reviewed many key technical considerations in depth. *Project Manager: A. B. Long*

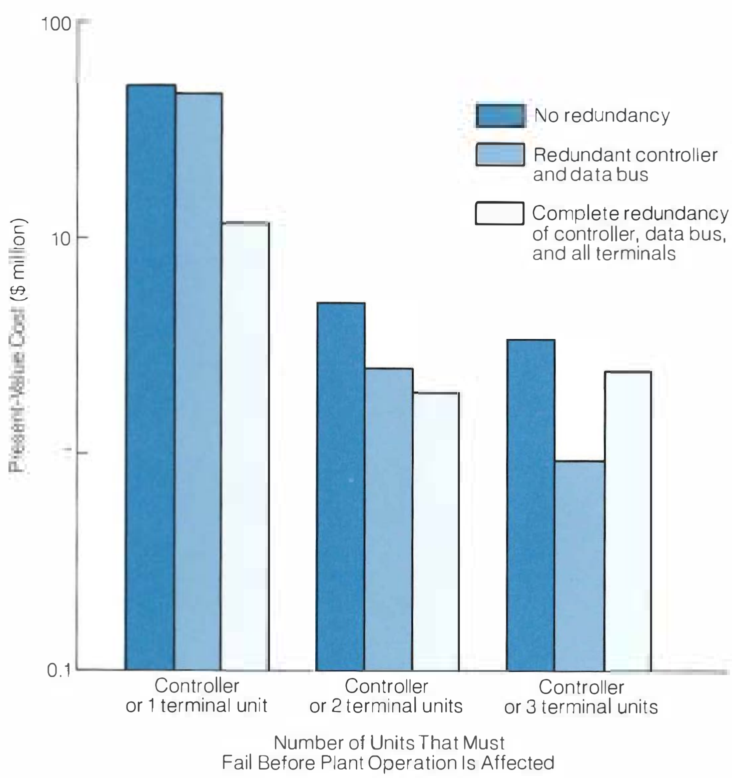


Figure 3 Present-value costs (including initial costs, maintenance, and operating penalties) are shown for remote multiplexing systems with differing degrees of redundancy. The set of columns on the left illustrates that a fully redundant RMS will save tens of millions of dollars if the failure of any one terminal or controller impacts plant operation. However, the set of columns on the right indicates that, when individual terminals are less critical to plant operation, the most cost-effective RMS design need have only redundant key elements (controller and data bus).

LARGE-SCALE CRITICAL FLOW TESTING

In December 1977, an 18-month series of nuclear reactor safety experiments to measure discharge mass flow rates from reactor-size, large-diameter pipes was initiated at the Marviken Test Station in Sweden. The project is internationally supported by organizations in Denmark, Finland, France, Holland, Norway, Sweden, and the United States (RP956). The U.S. contribution is shared equally by the NRC and EPRI.

An important element in LWR safety analyses is the maximum discharge flow rate (critical flow rate) from coolant pipes. Current critical flow models are based, in part, upon small pipe experiments. There exists a need to obtain additional critical flow data from pipe sizes in the range of those present in reactor coolant systems. The objective of the Critical Flow Test (CFT) project is to provide these additional data. The results from these experiments can be used to gain a better understanding of critical single- and two-phase flow in large-diameter pipes and also to develop an improved analytic model to be used in LOCA analysis applications.

The discharge mass flow rates used in LOCA licensing calculations are believed to be conservative. In other words, higher than actual discharge mass flow rates are calculated, causing more rapid depressurization and consequent early departure from nucleate boiling and higher peak clad temperatures. These calculated higher discharge mass flow rates may also cause the reactor recirculation pumps, under hypothetical LOCA conditions, to run at overspeed conditions, compared with their normal operation. The acquisition of data on critical mass flow rates for large-diameter pipes may affect these hypothetical LOCA performance characteristics.

The expected lower discharge rates would tend to decrease the transient loading of LWR containments. Blowdown forces that result from a pipe break and that affect the vessel itself and surrounding structures, components, and pipes can be more accurately calculated when the discharge flow rate from the break is better known.

Two-phase discharge has been investigated only in small-diameter nozzles (up to about 100 mm; 4 in), using water and steam-water as test media. The CFT project is unique in that, for the first time, large-scale-pipe flow measurements will be performed.

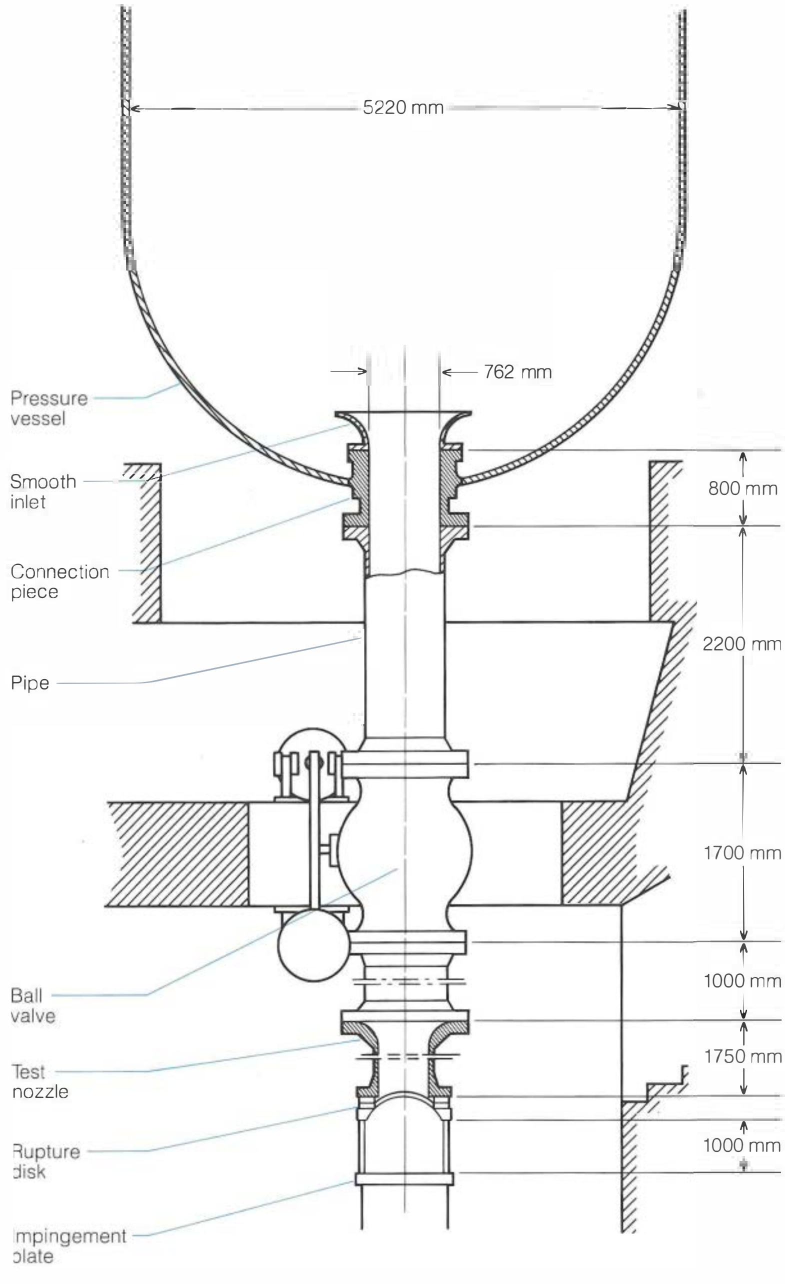
The test program includes over 30 transient blowdown tests that involve parametric studies of several variables. The main emphasis is placed on the influence of nozzle diameter, nozzle length, nozzle length-to-diameter (L/D) ratio, nozzle inlet subcooling, and system pressure. Other conditions and phenomena to be studied are water quality and possible double choking in the discharge pipe.

The Marviken Test Station contains a pressure vessel with a large steam-water inventory capacity. A 760-mm (30-in) discharge pipe is connected to the bottom of the vessel (Figure 4). This pipe contains a large ball valve, instrumentation, and rupture disks. At the lower end, any one of eight test nozzles can be attached. The nozzles have different diameters (200–500 mm; 8–20 in) and L/D ratios (1 to 3). For each test, initial conditions are established in the vessel. Generally, there is subcooled water in the lower portion of the vessel and in the discharge pipe, saturated water at higher vessel elevations, and a saturated steam volume at the top. Tests are initiated—with the ball valve in the open position—through pressurization of the rupture disks. The discharge fluid is released first into the containment and then to the atmosphere.

The pressure vessel and the discharge pipe are instrumented to measure pressures, temperatures, densities, fluid levels, and fluid velocities throughout the test facility. Particular attention is given to fluid conditions at the test nozzle entrance and in the nozzle itself to measure subcooled and low-quality fluid discharge characteristics (Figure 5).

The project is now in its shakedown phase, with tests being performed to check out instrumentation, data recording and reduction, and potential anomalies in test procedures. The test matrix is planned to be executed during 1978 and 1979.

Figure 4 Cross section of critical flow test (CFT) vessel at Marviken Test Station, Sweden, showing test geometry. This is being used in a project to measure data necessary to determine the discharge mass flow rate in the event of a hypothetical LOCA in a nuclear power plant.



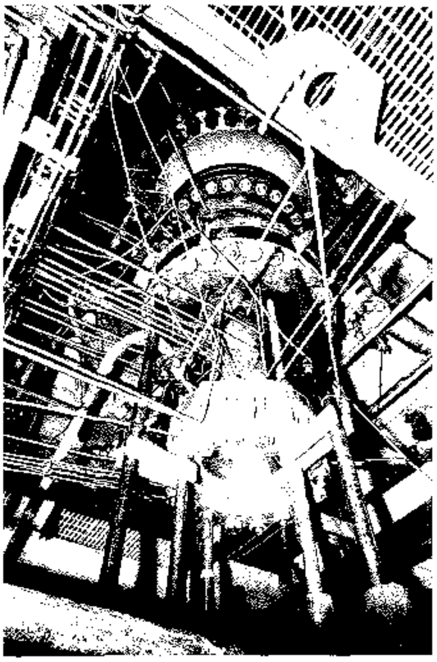


Figure 5 View of Marviken CFT nozzle and a portion of the test instrumentation.

DROP IN

Norrköpings Tidningar

MYNT köpes och säljes
AMNEKLEVS MYNTHANDEL

Simulerade haverier i Marviken förhindrar framtida katastrofer

Marviken världens förmodligen enda oljeeldade "kärnkraftverk" – fungerar idag som en reservstation att sättas in i elproduktionen vid toppbelastningar, tider med låg energitillgång t ex torrår eller om något annat kraftverk står stilla på grund av reparation. Under 1977 producerade 600 miljoner kraftverket elektricitet till riksnätet under 150 timmar.

Enda oljeeldade "kärnkraftverket" fungerar idag som reservstation

Figure 6 Full-page coverage of Marviken CFT project in the Swedish newspaper, *Norrköpings Tidningar*.

The project is receiving much attention because of its significance in reactor safety research. An example of this is the extensive coverage of the first shakedown test in a Swedish newspaper (Figure 6). Project completion is presently scheduled for the end of 1979. Total cost is estimated at $6.4 million. *Project Manager: K. A. Nilsson*

LASER PROCESSING OF THE SURFACE LAYERS OF REACTOR MATERIALS

Laboratory investigations have identified the critical role played by the structure of the surface layers of two important alloys that are used in light water reactors. These alloys are susceptible to stress corrosion cracking (SCC) under certain operating conditions. This is a brief review of the microstructural features of these materials that lead to cracking and of some preliminary work on a surface-processing treatment that can make these alloys more resistant to cracking.

Austenitic type-304 stainless steel is widely used as piping material because of its excellent corrosion resistance under many conditions and its strength and ductility. Under certain conditions, however, it can become "sensitized" and thereby susceptible to intergranular SCC. Incidents of SCC associated with weld-heat-affected zones were observed in several BWRs in 1974 and occasionally before that.

Due to the high temperatures reached by the base metal adjacent to welds, carbon precipitates out along grain boundaries in the form of chromium carbide, $Cr_{23}C_6$. The extent of precipitation increases with the amount of time spent in the sensitization temperature range (~400° to ~800°C). The reduced chromium concentration in the alloy next to the grain boundaries is apparently the cause of susceptibility to SCC.

If metal is cooled very rapidly, sensitization can be avoided and the corrosion resistance increased. The required cooling rates often cannot be provided for large pipes or castings. Also, concern about introducing thermal stresses often precludes a rapid quench.

In the reactor core, a zirconium alloy, Zircaloy, is used for fuel cladding. After moderate burnups corresponding to about one-half the nominal lifetime of the cladding, a rapid power increase can occasionally lead to crack initiation in the cladding. Evidence from EPRI programs and elsewhere suggests that this type of cracking is due to stress corrosion of the Zircaloy, with the cracks originating at the inner surface of the tubing. Those features of Zircaloy that render it susceptible to SCC are being investigated by SRI International (RP455-1).

Upon exposure to iodine and a high stress, small intergranular cracks were observed to start at microstructural inhomogeneities at the inner surface of the cladding. These cracks penetrated only to a depth of ~10 μm and did not appear to propagate. Larger cracks were also observed in ~30% of the test specimens. These cracks were consistently associated with high local concentrations of alloying elements or tramp impurities, such as Fe, Cr, Al, and Si. Preliminary results suggest that only under stresses in excess of the threshold stress for iodine SCC were the larger cracks observed.

Both type-304 stainless steel and Zircaloy cladding are made susceptible to cracking by the local surface concentrations of particular chemical species. One method for avoiding such vulnerable surfaces (i.e., making them more resistant to SCC) would be to remelt and rapidly self-quench a thin layer of the surface so as to effect a more uniform distribution of alloying elements. Currently available lasers provide enough energy for such rapid melting and resolidification of thin surface layers. Laboratory experiments have been initiated to test whether such surface treatment is practical.

General Electric Co. has laser-treated type-304 stainless steel that had been previously heat-treated to sensitize the samples. Susceptibility to cracking was evaluated by an accelerated corrosion test. Complete absence of intergranular attack was observed in specimens that were treated with the laser. Grain boundary attack was observed in the unprotected ends of the specimens that had not been laser-treated.

EPRI and United Technologies Corp. have initiated a study to evaluate the prospects of improving the resistance of Zircaloy by laser-treating the surface (TPS77-733). The objective is to determine whether homogenization of the impurities found in the surface layers occurs sufficiently to make this material more resistant to crack initiation. So far, procedures for laser-treating Zircaloy have been developed. Tests to evaluate changes in surface composition, structure, and susceptibility to cracking are under way. *Project Engineer: Howard Ocken*

R&D Status Report
ELECTRICAL SYSTEMS DIVISION

John J. Dougherty, Director

One of the little-recognized aspects of EPRI has been our loaned-employee program. Since the Institute began operations, a system has been in use under which the EPRI member organizations nominate one of their employees to serve for a period of a year or more on the EPRI technical staff. At any one time there are usually several such loaned employees in each of the technical divisions.

The benefit to EPRI of such a program is far greater than might be recognized at a glance. Such employees provide insight into the industry's needs that is probably not attainable in any other way. Coupled with the regular interface between the industry advisory committees and task forces, they are indispensable in keeping the Institute's goals in line with the practical needs of the utility industry.

Our satisfaction with the program is perhaps best reflected in the fact that we often seek to extend the stay of a loaned employee for an additional few months after the normal loan period has expired. Moreover, as nearly as we can ascertain, the loaned employees have found the time spent at EPRI rewarding in terms of personal accomplishment and opportunity for personal growth.

There is one flaw in the loaned-employee program, which only the utilities can remedy. For the main part EPRI has accepted all the loaned employees offered to date. They have invariably been high-caliber personnel, but they are not always specialists in the disciplines in which the staff most needs assistance. To further improve the system, members should make a concerted effort to offer many more employees for use in this program. Such a plethora of nominations would not be used to greatly increase the number of loaned employees resident at the Institute but rather to make it possible to choose personnel with the backgrounds most needed at any given time.

In the few years since the Institute was formed, there have been a dozen utility engineers who have been on loan to the Electrical Systems Division (four of these are now on board). They have been drawn from utilities all over the United States, and one was loaned from the Swedish State Power Board. They have come from large metropolitan utilities and from rural electric cooperatives.

In summary, we have made good use of the loaned-employee concept over the past five years, but we need the industry's help to continue and improve the program. Each year, EPRI member utilities receive a request for nominations from the Institute. We would like to see an even better response than in the past. The program offers one more way in which member organizations can become more involved in and more knowledgeable about the programs at EPRI. The EPRI research program is funded by the member organizations' contributions; therefore each member has a vested interest in helping EPRI utilize these funds for maximum benefit. *John J. Dougherty, Director*

OVERHEAD TRANSMISSION

Longitudinal loading

Prior to the mid-1950s, relatively little attention was given to longitudinal strength requirements for transmission line systems. Hundreds of thousands of miles of line were installed on directly embedded wood poles, providing very flexible mechanical systems that were essentially self-protecting against cascading failures. When metal structures were used, they were predominantly square-based, lattice steel towers with equal or nearly equal transverse and longitudinal strength. They were usually required to sustain one or more broken conductors or broken overhead ground wires.

After the mid-1950s, as voltages and line capacities increased and support structures became larger and heavier, transmission engineers began to focus on the impact that longitudinal strength had on structure cost. Some were encouraged to drastically reduce the longitudinal requirements on structures for new lines. The cost of over-building as opposed to the risk of under-building has become a matter of serious concern to transmission line designers.

It is within this context that EPRI funded a project undertaken by GAI Consultants, Inc., to evaluate the effect of structure design parameters on longitudinal loads and to prepare a design guide for use by the utility industry (RP561).

The first task consisted of a review of the codes and guides currently being used for the design of transmission line systems and a review of professional opinion on the subject, as expressed worldwide in technical papers, articles, and published discussions (EPRI 561). To complete the picture, six U.S. electric utility companies were interviewed about their present practices.

The second task was the development of a computer program for calculating static load and displacement caused by broken wire or differential ice conditions. The program incorporates the behavior of all elements of the transmission line system, including the nonlinear force-displacement relationships of the conductors, shield wires, and insulator strings, as well as the flexibilities of the support structures. The result of this work is the computer program BRODI I, which is available for use by utilities.

The third task in the project was the determination of impact factors that result from the release of stored energy when a wire breaks. Laboratory tests were conducted on a model transmission line to measure dynamic loads associated with broken wires. The primary result was the development of a design procedure for estimating impact factors for the support structure loads. The static loads determined from the computer program are multiplied by these impact factors to yield the peak dynamic loads and moments on the support structures.

The output of this effort is to be a design guide that includes readily available computer programs, simplified design curves and equations, and/or tables. These aids are expected to make the calculation of unbalanced longitudinal loads considerably easier for the transmission line design engineer. The design engineer will still be responsible for making all decisions concerning the anticipated loads for which he will design. The EPRI design guide is intended to help him perform his calculations more easily and quickly.

The analytic and laboratory work is now complete. Engineers at GAI, the University of Wisconsin, and EPRI are correlating data from this project with data received from actual field tests (RP1096). It is especially important that apparent discrepancies between data from the two projects concerning impact factors be fully understood. Shortly after this phase of the study is complete, EPRI will publish the design guide, complete with documentation for the computer program BRODI I. *Project Manager: Richard Kennon*

Leak locators

The objective of RP7869, being conducted by Power Technologies, Inc. (PTI), is the development and testing of an advanced, accurate system for locating leaks of cable oil and cable gas. The gases involved are nitrogen and sulfur hexafluoride.

Some utilities with extensive underground transmission circuits in large metropolitan areas have encountered serious and expensive leaks leading to shutdown of the pipe-type cable. In some instances, oil leaks have lasted for months because present location methods failed to find them.

This contract with PTI is intended to provide the necessary research and developmental testing to arrive at an accurate and expedient leak location system. Existing location methods will be studied during a state-of-the-art review and the advantages of each method will be assessed. Other approaches will also be assessed, such as those employing flow metering, acoustic signal injection, tracer gases, stable isotopes, infrared surveying, and possibly ground-penetrating radar. Combination of these and other novel approaches may result in a universal location system applicable to both oil-filled and gas-insulated cables.

The final system will have two modes of operation. The first will define the general location of the leak (for example, in an area between particular manholes). The second mode, using either one or a combination of methods, will pinpoint the leak. The system should be able to detect leaks with rates as low as 0.0114 m^3/h (3 gal/h).

The system will be proof-tested on oil-filled and gas-filled utility cables that exhibit leak problems. *Project Manager: Tom Rodenbaugh*

Taped cables

The technology now used for splicing most high-voltage paper-insulated cables was developed more than half a century ago. This technology depends on highly skilled technicians for assembly of the joints in the field and is very time-consuming and expensive. It is also generally recognized that most current joint designs are the weakest elements in underground transmission systems.

A jointly funded EPRI–DOE project that addresses the problem was recently completed by Phelps Dodge Cable & Wire Co. (RP7814). Development of a 345-kV, capacitive-graded joint for pipe-type cable had as its goals lower-cost installation, shorter installation time, routine manpower require-

UNDERGROUND TRANSMISSION

Cryogenics

Progress continues to be made in the development of a superconducting material for cables. When last reported, a project with the University of California, Los Alamos Scientific Laboratory had achieved a breakthrough by producing Nb_3Ge with losses at 12K that were comparable to those of the best Nb_3Sn samples at 4K. This factor-of-3 increase in the operating temperature implies a reduction in refrigeration needs of a similar magnitude.

Recent effort has been directed toward producing long lengths of Nb_3Ge tape with a high current-density capability. Thus far the effort has been successful in producing 50 m of tape in lengths up to 20 m. The Nb_3Ge has been deposited on Cu and on Nb substrates with critical current densities of up to 2.4×10^6 A/cm^2 at 13.8K. This accomplishment is unmatched in the world today.

Logically, the next step is to develop a cryogenic dielectric capable of operating at these higher temperatures, but this is not within the scope of the present contract. *Project Manager: Mario Rabinowitz*

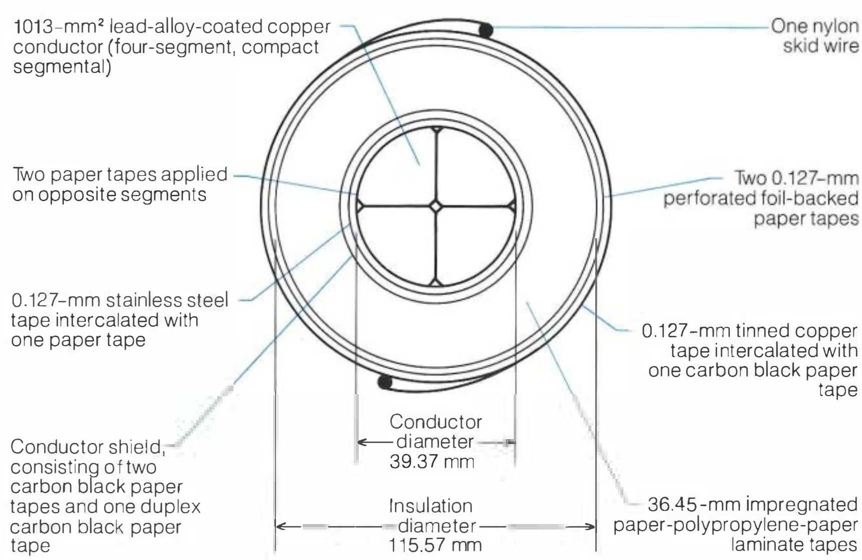


Figure 1 Second-generation design for 765-kV HPOF cable recently tested at the Waltz Mill cable test facility in Pennsylvania.

ments, less demanding environmental humidity control, and increased reliability through factory-testing of components.

The capacitive-graded joint developed in this project deviates considerably from conventional joint designs and requires the use of a new type of capacitive material.

Present manufacturing technology was found to be incapable of producing the required capacitive sheets in any reasonable volume. Two techniques for making capacitive material were investigated, but neither approach produced consistently adequate material. In order to develop a commercially successful joint, development of the technology for manufacturing capacitive sheets is required. This developmental work is planned for the near future.

Extending the capabilities of existing laminar-dielectric cable technology to beyond 500 kV is desirable for underground transmission utility systems. Laminar dielectrics, or taped cables, have a mature technology with well-developed manufacturing and field-handling techniques. Thus, improvements can be made in quality or materials to meet specific future needs while basic system structural features are retained; this carries the advantage of manufacturer and user familiarity and hence easier acceptance.

At 765 kV, the use of cellulose paper–oil cable incurs a heavy dielectric loss penalty. This is because of the charging current that a cable system draws when it is energized, regardless of power flow. In order to use taped cables in the UHV range, a cost-effective, workable, low-loss combination of synthetic tape and fluid impregnant must be found. Such a unique combination has been elusive, largely because of economic constraints and compatibility problems between the tape and its impregnant.

Phelps Dodge is developing a reliable 765-kV cable system under a long-term, jointly funded project with EPRI and DOE (RP7812). Thermal, fluid flow, electric stress, and cable geometry problems frequently make the performance of a cable system difficult to predict mathematically. Even modeling can result in scaling errors. Expensive, full-size cables must ultimately be constructed and tested to determine actual performance. This full-scale testing frequently uncovers unforeseen problems. In 1976, the project was completely restructured, using all past data and results as a foundation for the new effort.

The present design of the 765-kV HPOF cable is shown in Figure 1. The results of recent testing have been much more encouraging. Data are shown on the first redesigned sample, which uses a cellulose paper–polypropylene film "sandwich" tape with a specially treated polybutene oil impregnant (Figure 2 and Table 1).

While there are still additional problems to overcome, it appears that a cost-effective, workable, low-loss cable has been developed that more than meets the dielectric requirements of 765-kV systems. *Project Manager: John Shimshock*

Table 1
SUMMARY OF ALL EHV TESTS ON SINGLE CABLE SAMPLE

Test	*Maximum Applied Voltage (kV)*	*Maximum Stress (kV/mm)*	*Maximum Stress (V/mil)*	*Conductor Temperature (°C)*
Ac step	1150	55.3	1405	85
Switching surge	1675	80.7	2050	90
Impulse surge	2750	132.3	3360	90

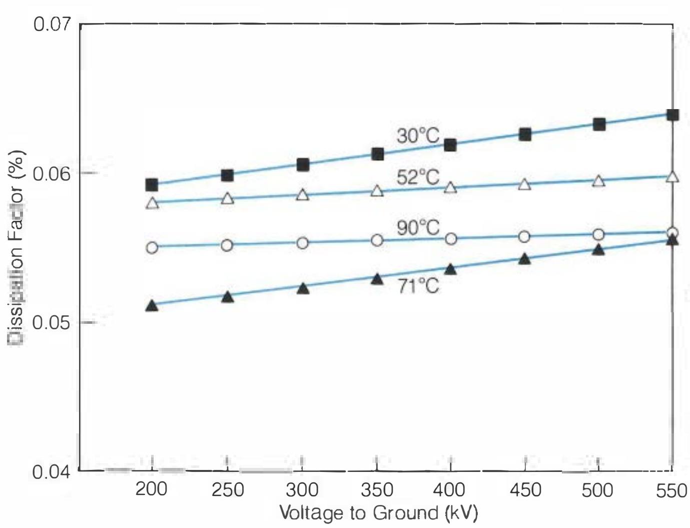


Figure 2 Cable dissipation factor of prototype 765-kV HPOF cable charted against applied voltage at various conductor temperatures after completion of load cycling.

SUBSTATIONS

Instrumentation

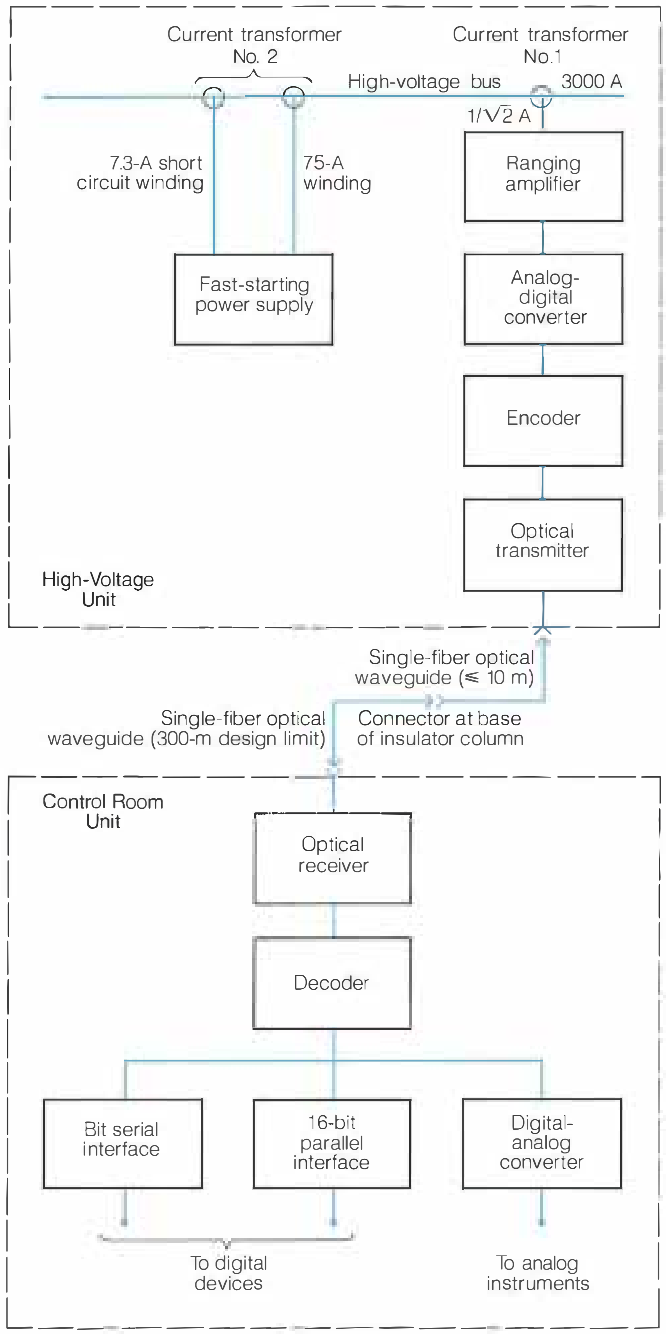
Many attempts have been made to build electronic current transducers (ECT) for high-voltage transmission lines. The idea is simple and attractive. The cost of conventional free-standing current transformers (CTs) for high-voltage transmission lines is substantial, and a catastrophic CT failure (explosion) is of concern, as it is a hazard to both people and equipment. Porcelain fragments could damage insulators and bushings of nearby equipment. The fire hazard and the outage that can result from CT failures are additional reasons to continue the search for better current measurement methods.

Previous attempts to build ECTs have not been successful, since (in spite of all its problems) a conventional current transformer is a surprisingly good measuring device. It has high accuracy and good resolution for metering purposes. It has a large dynamic range with reasonable accuracy for relaying purposes, even though it does suffer from saturation problems. It also has a relatively high frequency response, which is useful for fault analysis. Because conventional CTs have been so strong in these areas, it has been difficult to get equal performance from ECTs.

Under EPRI sponsorship, a digital EHV current transducer is being developed by Westinghouse R&D Center, Pittsburgh (RP 560). The target specification for the transducer was to meet metering, relaying, and fault recording requirements with one unit. The frequency response, specified at 10 kHz minimum, should be adequate for future current limiter control systems and ultrahigh-speed relays as well. Digital techniques were specified for the conversion and signal transmission system of the ECT in order to gain experience with a design that could be directly interfaced with future digital protective relays. Fiber-optic links were specified for the communications system.

An ECT that meets the above specifications has been designed, built, and tested by the contractor. The ECT shown in Figure 3 makes use of a 12-bit analog-to-digital converter, combined with a ranging amplifier that gives an effective dynamic range equal to 16 bits, but with 12-bit resolution. The ECT meets metering accuracy requirements of the lower range and relaying requirements in both ranges. The ECT has been designed to operate in temperatures ranging from −40 to +85°C. The bandwidth of the unit is good for 10–15 kHz, since the sampling rate is one sample every 22 μs (i.e., one sample for every half electrical degree on a 60-Hz basis). The estimated mean time between failures for the electronics equipment of the high-voltage unit is approximately 50,000 hours, which means that the mean time to failure for two parallel redundant units is about once every 500 years, if one assumes about one week's mean time for repair. This does not include the ground

Figure 3 Electronic current transducer (ECT) incorporating a single, 300-m-long waveguide for signal transmission between the high-voltage unit and the control room unit. The ECT is built for the substation environment. Its 12-bit resolution, 16-bit dynamic range, and 10-kHz bandwidth satisfy all current accuracy and speed-of-response requirements for metering, relaying, oscillographic recordings, and so on. It may suffice for future ultra-high-speed relaying requirements as well.



electronics unit, which is much simpler to repair because it does not require access to the high-voltage circuits.

A major development effort of the project was the design of the fast-starting power supply unit feeding the electronic equipment at high potential. The power is taken from current transformer No. 2 and connected in line with the ECT unit. The fast-starting power supply makes the ECT fully operational within 200 μs, assuming that a 4 per unit short circuit current is starting to flow through the CT. The time is counted from the zero crossing of the current. The power supply will maintain operation of the ECT down to about 2% of rated current. This means in broad terms that the ECT will be fully operational before the insertion resistors used in most 500-kV breakers are bypassed. In fact, the frequency response of the unit should be adequate for detection of ground faults or short circuits on a line being energized prior to bypassing of the insertion resistors if an ultrahigh-speed relay were connected to the ECT.

The developed ECT makes use of single-fiber optical waveguides made by Siecor. The design length for the optical link is 300 m, but it will be tested in a Bonneville Power Administration substation using about 420 m of optical waveguides. The outputs provided by the ECT are capable of driving solid state protective relays (assuming that the 5-A current input is bypassed) and will produce bit-serial and bit-parallel digital outputs that can be processed further in digital equipment.

The unit will be installed in a Bonneville Power Administration 500-kV substation for one year's evaluation. Three additional units have been ordered separately by Pennsylvania Power and Light Company for research and development of digital protective relays. *Project Manager: Stig Nilsson*

Light-fired thyristors

One of the keys to obtaining increased benefits from HVDC transmission schemes and other thyristor-controlled systems is a reliable, simple, inexpensive thyristor valve module that can be used as a building block for various applications. One means of simplifying thyristor modules is to have the thyristor triggered by a light pulse directly applied to a light-sensitive area on the thyristor wafer. This provides the necessary electrical isolation and also eliminates the need for high-voltage pulse transformers and auxiliary power supplies now required for electrically fired thyristors. Light-fired thyristors are also immune from electromagnetic noise interference.

The feasibility of light-fired thyristors has been proved through two EPRI projects: RP567 with Westinghouse R&D Center, Pittsburgh, and RP669 with General Electric Co. Corporate R&D Center, Schenectady.

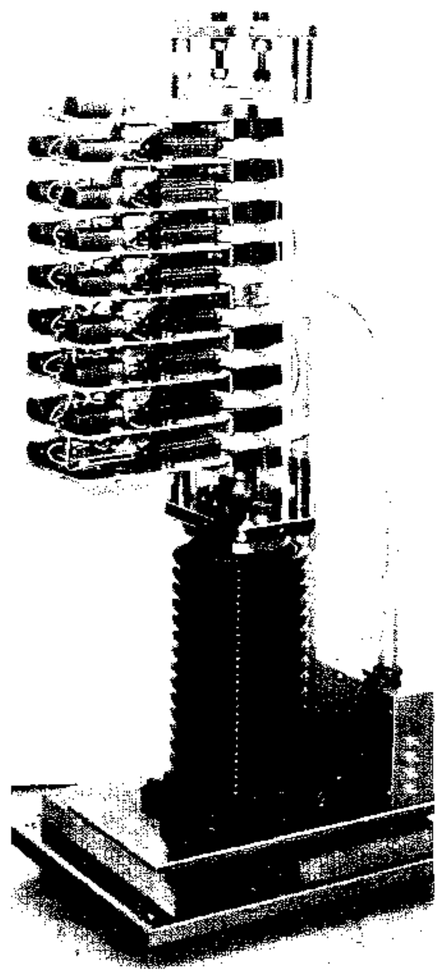
The Westinghouse project will demonstrate the application of light-fired thyristors in a controlled volt-ampere-reactive (VAR) generator. A series stack of eight light-fired devices was built and tested under laboratory conditions and met the requirements of its electrically fired equivalent (Figure 4). The next phase of the project will involve optimization of light-fired thyristor systems, design and fabrication of a 15-kV switch, and incorporation of the switch in a static VAR generator (currently installed on Minnesota Power & Light Co.'s 230-kV system). The switch will be monitored to obtain operating experience with light-fired thyristors in this field application.

The General Electric project emphasizes development of light-fired thyristors applicable to HVDC converter terminals. This involves exploration of thyristor sensitivity to various light levels, improvement of their voltage and current rate-of-rise capability, and investigation and design of self-protecting devices, which would eliminate additional circuitry and electronics now necessary in HVDC thyristor applications. Design of a valve module that would serve to replace its existing electrically fired equivalent is a part of this project phase.

Light-fired thyristor development will become a portion of a new project to develop an advanced thyristor valve module. The advanced valve will make use of not only light-firing but also larger-diameter wafers for increased blocking voltage, protection against forward and reverse overvoltages, and improved thermal characteristics through the use of two-phase cooling.

The development of an advanced HVDC thyristor valve will be a key component in the use of HVDC as a valuable and economical tool in providing for tomorrow's energy requirements. *Project Managers: Narain Hingorani and Ivars Vancers*

Figure 4 One-half of a static VAR generator switch module, showing water-cooled, light-fired thyristors.



DISTRIBUTION

Surge propagation and attenuation

Designing surge protection for underground distribution systems is problematic because the propagation and attenuation of surges is not completely understood. The majority of underground residential distribution (URD) systems are extensions of overhead distribution lines, connected by an overhead-underground junction. Surges caused by lightning striking the overhead line enter the underground systems via the overhead-underground junction. Other surges are generated within the underground systems by fault-interrupting devices such as current-limiting fuses and by the fault currents themselves.

It has been common practice to install surge protection at the overhead line–cable junctions and, frequently, at the open end of the cable. The open end protection is necessary because the surges travel through the cable at the rate of approximately 150 m/μs, and the surge voltages double at the open point. A common belief is that surge protection devices installed at the open end will adequately protect the cable and connected equipment. However, equipment failures continue to occur, and the cause is unexplained.

A research project (RP795) was initiated by EPRI to assemble available experimental and analytic data, perform required laboratory tests, and develop computer models and modeling techniques to study surge behavior of underground distribution systems. The McGraw-Edison Co., Power Systems Division, was the contractor.

Models of the various distribution system equipment, such as transformers, cables, and lightning arresters, have been developed. Different surge characteristics (steep front waves, long tail surges, and so on) have been studied to characterize the effects of the surge voltages on the underground distribution systems. A summary of viable surge protection schemes for underground distribution systems is provided in the final report (EL720).

The project results provide tools that will enable the distribution engineer to study surge protection requirements for each specific system. Thus, distribution systems can be designed with confidence that the best possible surge protection scheme is included.

Results of this project also confirm that most surges entering underground cable systems are not attenuated significantly. Cable circuit lengths in excess of 600–900 m are required before surge attentuation becomes a design consideration. The connected transformers, whether loaded or unloaded, do not affect surge propagation, except for very steep front waves. The surge voltage propagated in one phase of a three-phase circuit does not induce voltages in the other two phases. Insulation coordination studies for specific systems will indicate which protective system is appropriate for a given set of conditions.

One major link to more effective insulation coordination is missing—namely, the response of equipment insulation to the very steep front surges with rates of rise above 500 kV/μs. *Project Manager: Bill Shula*

SYSTEM PLANNING

Long-term power system dynamics—hybrid simulation

The University of Missouri at Columbia has built a scaled electrical model of a power system, including representation of the load, transmission network, dispatch center, and the power plants, for use on a hybrid computer (RP908). The electrical characteristics of the power system were modeled on the analog computer while the digital computer monitored the control functions of the analog computer and provided data logging. Such an arrangement achieves the high computation speed of the analog computer (the model power system can operate twenty times faster than real time) while retaining the convenience of data input-output monitoring and functional control flexibility provided by the digital computer.

The hybrid computer is capable of simulating power system behavior under severe generation deficiencies, such as those caused by the loss of major generation units and/or major tie lines. It can also perform load flow and transient stability simulation. These capabilities of the hybrid simulator have been demonstrated, and the accuracy of the simulation has been validated by digital computer programs. Its excellent reliability has been proved by actual hands-on experience.

Four potential applications for the hybrid computer have been identified:

- A national operator training center
- A research tool to evaluate the system impact of new technologies
- A planning tool for evaluating the impact to the power system's electrical performance under new expansion alternatives
- An operator's tool for on-line assessment of system security

Three independent consultants were retained by EPRI to assess the hybrid computer's market potential for each of the potential applications. The conclusion of the consultants' evaluation was that although the hybrid computer can meet all the practical requirements (such as accuracy and flexibility) by using high-quality electronic components and by applying state-of-the-art hybrid computer technology, cost is a major roadblock. A survey of over 50 utilities indicated that the cost of a commercial-quality hybrid computer is at present considerably higher than most utilities would support as an in-house computing facility. However, this does not rule out the benefits of the hybrid computer as a national operator-training center or as a research facility. The project is now complete and the final reports, EPRI 908-1 and EPRI EL-724, are available. *Project Manager: Tim Yau*

R&D Status Report
ENERGY ANALYSIS AND ENVIRONMENT DIVISION

René Malès, Director

DEMAND AND CONSERVATION

Heat pumps

In 1975, EPRI and the Association of Edison Illuminating Companies began work on a jointly sponsored project (RP432) to investigate the load and energy use characteristics of electric heat pumps in single-family housing units. The main objectives were to obtain information on heat pumps and to identify the major factors contributing to energy use in homes. Westinghouse Electric Corp. has been the principal investigator in this research. The draft final report, which has been reviewed by both EPRI staff and various experts in the utility industry and elsewhere, will be released shortly.

The study focuses on the operating characteristics of heat pumps in use in 118 single-family housing units in 12 utility service areas. These service areas represent a heating spectrum that ranges from 250 to 8250 annual heating degree days. Physical data were collected from November 1975 to June 1977. Only recent designs of heat pumps were chosen because they best approximate future technology and use. Among the variables measured for each installation were compressor energy for heating, compressor energy for cooling, supplementary heater energy, total house energy, inside house temperature, indoor fan energy, time, solar insolation (total and diffuse), outside dry-bulb and wet-bulb temperatures, humidity, pressure, and wind velocity. One principal goal of the project was to determine seasonal performance factors for heat pumps installed in single-family homes. By using actual field measurements, the research sought to determine heat pump heating system energy and power requirements as functions of climate, house size and type, number of occupants, internal loads, and heat pump model and size. In addition, attempts were made to determine the effect of heat pump systems on peak demand and on load profile. Other goals included determining the accuracy of energy modeling algorithms for buildings and developing more information about heat pump reliability. Also, performance factor analysis and reliability information from the research might suggest some product improvements.

Finally, each utility participated in an opinion survey that was conducted at the end of the study. The survey identified the more subjective factors that contribute to heat pump acceptance or rejection in the marketplace.

Demand 77

Volume 1 of *Demand 77: EPRI Annual Energy Forecasts and Consumption Model* (EA-621-SR), a special report that summarizes in-house research results, is now available from Research Reports Center. The report presents conditional forecasts of national energy consumption based on alternative assumptions concerning energy prices, conservation policy, and natural gas availability. The forecasts cover each end-use activity and each form of energy. The forecasting models, which were developed through EPRI contracts or adapted from other forecasting studies, are based on statistical relationships characterizing past energy consumption behavior. Thus, the orientation of the forecasts is on how much energy is *likely* to be consumed rather than on how much could or should be consumed. Volume 2 of the report (in preparation) documents the forecasting procedure and the assumptions in detail.

Patterns of energy use

The final report on patterns of energy use by electrical appliances will soon be published (RP576). Midwest Research Institute was the contractor for this two-year project, which was cosponsored by DOE. A detailed national survey of 1985 households was conducted by personal interview, and monthly energy consumption data were collected from individually metered appliances in 150 homes. The research findings will be valuable because they reflect the first national sample of household appliance usage that is supported by a thorough characterization of related economic, demographic, and meteorological variables.

The report includes tables that describe the monthly variations in energy consumption for such electric appliances as washers and dryers, refrigerators, freezers, and ranges. These results are also reported by geographic region. Other tables describe appliance and total household energy consumption by income class, number of rooms in the home, number of household members in the labor force, type of residential area, and family size. Energy consumption patterns for frost-free refrigerators are compared with those for manual-defrost units, and usage patterns for room air conditioning are contrasted with patterns for central air conditioning. The contributions to total household energy consumption of individual appliances are of particular interest because they show relatively large variations by season and geographic region.

The project results have already made an important contribution to the public dialogue on appliance efficiency standards and labeling legislation. The research also supports EPRI forecasting efforts such as RP1006, an analysis of household appliance choice, and RP1211, an analysis of survey data on household time-of-day and annual electricity consumption. The latter project will use a number of data sets to develop a microsimulation model of residential energy consumption. This model will be designed to analyze the impacts of time-of-day and seasonal pricing, load management strategies, appliance efficiency standards, market penetration of new appliances, and changing building and insulation standards. *Program Manager: Robert Crow*

SUPPLY

Uncertainty about the future is a crucial element in decisions to expand energy supply. Uncertainty, which has always been a fact of life in decision making, can be divided into two types. One may be characterized as conventional uncertainty. Successful individuals and organizations have developed a wide variety of methods, from experienced judgment to very formal analysis, to deal with this type of uncertainty. This type provides little impediment to the expansion of energy supply—it is simply a part of doing business.

The second, unconventional type of uncertainty involves new uncertainties or new levels of uncertainty. Changes in federal and state environmental and energy policies are examples of this type. Other such uncertainties can also affect R&D. How will technologies perform? What will their environmental consequences be? What will their costs be? What rates of adoption will occur? There has been little or insufficient experience with uncertainties of this type. Moreover, they are difficult for decision makers to deal with in a rational way.

The Supply Program is directing a small but important research effort toward understanding how uncertainties, particularly of the second type, will influence the development of the nation's energy supply. In particular, the research examines the adoption of new technology under uncertainty and considers how such effects can be incorporated in energy models. Two of the projects in this research effort have reached fruition.

In a report by Microeconomic Associates, *The Effects of Risk on Price and Quantities of Energy Supplies* (EA-586), the causes and consequences of uncertainty for the energy sector of the economy are discussed and approaches for analyzing specific uncertainties and risks are described. Topics included are: the value of diversification of research approaches; prebidding exploration for oil and natural gas; incorporation of features in power plants to facilitate conversion to other fuels; diversification between coal- and nuclear-fired plants, even when one type produces power at a lower cost; ownership of uranium- and coal-bearing lands by utilities; and the effect of uncertainty on appropriate levels of generating capacity.

Of particular interest to utilities is the report's findings on the Averch-Johnson effect. This hypothesis holds that (ignoring risk) utilities subject to rate-of-return regulation will choose excessive levels of generating capacity and capital-intensive types of capacity. The report shows, however, that under conditions of risk, a firm may minimize expected costs by building more capacity than would be justified under certainty. Rather than being excessive, the capital stock may be at or below the efficient level to cope with risk.

An overview is available of the economic theory of uncertainty and its implications for energy supply (EA-586-SR). It shows that although the production function for the energy sector has received extensive study in recent years, most such studies focus on conventional inputs—labor, capital, and raw materials—and ignore risk bearing. Yet uncertainty is likely to play an important role over the next half century in determining changes in costs of production and output. The state of the art is far less developed for considering risk than for analyzing the role of conventional inputs. For this reason, the project attempts to lay the groundwork for estimating uncertainty effects.

At the applied level, a methodology for incorporating uncertainty in energy supply models has been developed by The Futures Group (EA-703). Uncertainty is incorporated by randomly introducing future events that have a significant impact on the system and by introducing uncertainty ranges for important exogenous factors. Cross-impact analysis (i.e., analysis of the interaction between events) and Monte Carlo techniques are used to combine this information with a basic simulation model to produce uncertainty ranges for the model's output. The technique, called probabilistic system dynamics, is demonstrated using ELECTRIC3, a model of the U.S. electric utility system. *Project Managers: Al Halter and John Chamberlin*

SYSTEMS

Alan Manne of Stanford University has succeeded in linking MACRO, a macroeconomic growth model of the United States, with his previously developed energy technology assessment (ETA) model in RP1014. In the combined model, the rigidity of the energy-GNP ratio is measured by a parameter called the elasticity of substitution. Attempts are under way to develop an authoritative estimate of that parameter. The combined model, ETA–MACRO, has been used extensively in technology assessment of the breeder and in ERDA's inexhaustible-resources study. The structure of ETA–MACRO is described in EA-592.

For Energy Modeling Forum's first study (RP875), an overview report has been published and work is under way to complete and publish the technical appendixes. The study examined the probable future relationship between the growth rates of U.S. energy input and national income. The overview report is available from Research Reports Center (EA-620). Forum's second study, on coal, has brought energy modelers and users together to investigate the reasonableness of the Carter Administration's goals for coal growth. A report on this second study is in progress. Forum's third study, on future demand for electricity, is being conducted by utility forecasters, state regulators, and members of EPRI's Demand Program. They are studying the probable future behavior of utility load growth under new pricing approaches.

PILOT, a linear programming model of the economy, was designed by a team headed by George Dantzig, the famous operations researcher. The model, which has recently been used in studies for DOE, is intended to explore future energy scenarios over a long time horizon. The PILOT group at Stanford University (RP652) has submitted a draft report to the Systems Program on progress it has made in constructing the model. The PILOT group is now working with EPRI's Planning Division in defining scenarios for R&D planning.

At a recent workshop, representatives from 15 utilities examined over- and under-capacity for generation (RP1107). This project analyzes decisions on optimal capacity additions under uncertainties about future load growth. The study was carried out jointly by four utilities (Tennessee Valley Authority, Pacific Gas and Electric Co., Long Island Lighting Co., and Wisconsin Electric Power Co.), a consulting firm (Decision Focus, Inc.), and members of EPRI's Systems Program.

A draft final report has been received from the Johns Hopkins University Applied Physics Laboratory on probable distribution of source effluents (RP953). This project developed a methodology for evaluating the effects of changes in environmental restrictions on the location of electric generating stations. The methodology has been implemented successfully for the northeastern region of the United States. *Acting Program Manager: Stephen Peck*

ELECTRIC UTILITY RATE DESIGN STUDY

The Rate Design Study (RP434) completed its second year with the submission of a major report to the National Association of Regulatory Utility Commissioners (NARUC) in November 1977. The report, *Rate Design and Load Control: Issues and Directions,* summarized the findings of two years' work and outlined areas in which additional research was needed. State regulatory commissions and individual utilities were encouraged to make their own cost-effectiveness studies of time-differentiated rates and load controls. Further, the report recommended that when such analyses showed that benefits of load management exceeded costs, these measures should be implemented gradually. Finally, the report to NARUC suggested that electric utility rates should reflect marginal costs to the extent possible. There were, however, differences of opinion about these findings, particularly on the subject of marginal costs. The views of the Project Committee are contained in the report to NARUC.

During 1977, some 50 additional reports were prepared for the Rate Design Study. These were distributed to the state commissions and utilities, in part to fulfill NARUC's request for research and information about slowing the growth in peak demand and shifting electric loads from peak to off-peak periods.

Additional research on behalf of NARUC is under way. During 1978, the Rate Design Study will do additional work on analytic models of electric utility systems for evaluating the changes in costs associated with various load management strategies. More work on developing time-differentiated rates based on both accounting costs and marginal costs is under contract. In addition, further research for determining price responsiveness and customers' attitudes is planned. Finally, some research will be done on methods for reconciling marginal cost–based rates to revenue requirements based on accounting costs. *Project Manager: Robert Malko*

New Technical Reports

Each issue of the JOURNAL includes summaries of 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 10090, Palo Alto, California 94303; (415) 961-9043. 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 pay a small charge. Research Reports Center will send a catalog and price list on request.

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Microfiche copies are available from National Technical Information Service, P.O. Box 1553, Springfield, Virginia 22151.

ENERGY ANALYSIS AND ENVIRONMENT

Nitrogen oxides: current status of knowledge

EA-668 Final Report (RP681)

This report by Greenfield, Attaway & Tyler, Inc., reviews the current state of knowledge regarding the health effects of nitrogen oxides, including nitric oxide, nitrogen dioxide, nitrites, nitrates, peroxacyl nitrates, and *N*-nitrosamines. A critical review is provided of existing toxicological, human clinical, and epidemiological assessment methodologies and data. Special consideration is given to the identification and explanation of the controversial issues surrounding health effects that have been related to ambient levels of NO_2/NO. Evaluation of existing information on the effects of suspended nitrates and airborne nitrosamines is emphasized. Suggestions are offered for future research programs involving the health effects of nitrogen oxides. *EPRI Project Managers: Cyril Comar, James McCarroll, and Ronald Wyzga*

Incorporating uncertainty in energy supply models

EA-703 Final Report, Vols. 1 and 2 (RP1012-1)

Although the U.S. energy system contains many uncertainties about future developments, existing energy models are deterministic and thus provide only single-valued projections. An understanding of the uncertainty associated with projections is very important to industry decision makers in assessing the risk involved with decisions.

This project by The Futures Group develops and demonstrates at a practical level a methodology for incorporating uncertainty in simulation models. Uncertainty is incorporated by introducing possible future events that would have important impact on the system if they occurred and by introducing uncertainty ranges for important exogenous inputs. Cross-impact analysis and Monte Carlo techniques are used to combine this information with the basic simulation model to produce uncertainty ranges for model output. The technique, called probabilistic system dynamics, is applied to ELECTRIC3, a model of the U.S. electric utility system. *EPRI Project Manager: John Chamberlin*

FOSSIL FUEL AND ADVANCED SYSTEMS

Geothermal energy prospects for the next 50 years

ER-611-SR Special Report

The material in this report was compiled for a report on unconventional energy resources that was prepared by the Conservation Commission of the World Energy Conference (WEC). Because of the necessity for brevity in the WEC report, much of the material was condensed. This report has been published for the benefit of those who may want more detailed information.

Three facets of geothermal energy—resource base, electric power potential, and potential nonelectric uses—are considered in light of information derived from three sources: (1) analytic computations based on gross geologic and geophysical features of the earth's crust, (2) the literature, and (3) a worldwide survey by questionnaire. None of these sources, nor any combination of them, fully satisfies the need for information about the potential for geothermal energy, but it is hoped that a more comprehensive assessment can be evolved as more data become available. *EPRI Project Manager: Vasel Roberts*

Electric utility solar energy activities: 1977 survey

ER-649-SR Special Report

The report presents the results of an EPRI survey to determine the scope of solar energy projects sponsored by electric utilities in the United States. It contains brief descriptions of 458 projects being conducted by 150 utility companies. Also included is a list of participating utilities that gives information contacts and addresses, a utilities list with projects designated by category, and a utilities list organized by state. *Prepared by Louise Cleary; EPRI Program Manager: John Cummings*

Comparative study and evaluation of advanced-cycle systems

AF-664 Final Report, Vols. 1 and 2 (RP235-1)

A number of advanced energy conversion concepts are now being proposed to supplement or supersede conventional power generation technology. They are being proposed by individuals and organizations with diverse backgrounds, using a variety of approaches and assumptions for predicting performance, cost, and development requirements.

The present work, undertaken by General Electric Co., analyzes 19 of the advanced concepts on a common basis, using uniform technical and economic assumptions. The concepts range from a steam cycle with an atmospheric fluidized-bed furnace to longer-term options, such as magnetohydrodynamic systems.

The primary purpose of this study is to define techniques for assessing the worth of these concepts to the utility industry and the nation as a whole. Three methods have been developed: levelized costing of electricity, direct weighting, and net present worth.

These measure not only the life-cycle costs associated with each power plant concept but also the intangible attributes, such as development risk and reliability. They assess the relative importance of costs and intangibles in the context of utility goals. *Prepared by Paul Zygielbaum. EPRI Program Manager: Vance Cooper*

Preliminary design manual for a geothermal demonstration plant at Heber, California

ER-670 Topical Report (RP580)

This report presents a preliminary design by The Ben Holt Co. and Procon Incorporated of a 50-MW (e) geothermal demonstration plant at Heber, California. The report includes a site description, a design basis, a process design, tradeoff studies to optimize plant operations, and an economic analysis of the plant.

The plant design provides flow diagrams and equipment specifications for the energy conversion system, the cooling-water system, the plant and instrument air system, the flare system, the firewater system, the electrical system, the piping system, instruments and controls, and buildings and structures. *EPRI Project Manager: Vasel Roberts*

An annotated bibliography on supplemental firing of municipal solid waste in electric utility boilers

FP-678 Final Report (TSA76-46)

This report by Battelle, Columbus Laboratories is an annotated bibliography of 86 articles on the subject of combined firing of refuse and conventional fossil fuels in utility boilers. The bibliography was compiled by machine-searching material, such as *Engineering Index* and *Chemical Abstracts,* and various literature search services, including National Technical Information Service, ERDA–RECON, Smithsonian Science Information Exchange, and EPA Air Pollution Technical Information Center. In addition, some literature references were found by searching appropriate journals and by personal contact with in-house and outside solid-waste conversion experts. Each article is indexed and categorized into one or more of seven subject areas. The bibliography does not cover other solid-waste conversion subjects, such as incineration, pyrolysis, and gasification. *EPRI Project Manager: Charles McGowin*

Geothermal exploration techniques: a case study

ER-680 Final Report (RP375)

The objective of this project by the University of Texas at Dallas was to review and perform a critical evaluation of geothermal exploration methods and techniques. The original intent was to publish the work as a handbook; however, the information is not specific enough for that purpose. A broad general survey of geothermal exploration techniques is reported, and one specific case study is given. *EPRI Project Manager: Vasel Roberts*

Coal-fired prototype high-temperature continuous-flow heat exchanger
AF-684 Final Report (RP545-1)

This research program was initiated by Airesearch Manufacturing Co. of Arizona to study the potential of using high-temperature ceramic components for direct coal-fired advanced utility power systems, which offer greatly improved efficiency and reduced component cost and maintenance. The program was organized to investigate important questions about the use of ceramics for this application. The material investigated was siliconized silicon carbide.

This work answered all the significant questions posed and justified continued effort. The property testing indicated that the strength levels were acceptable, but there was a wide disparity in the as-fired material strength between individual test pieces and also between the test pieces and the machined and polished samples. A recommendation was made to concentrate subsequent work on the improvement of the material strength in the as-fired condition and to further develop nondestructive test techniques for proper evaluation and characterization of these materials. *EPRI Project Manager: Arthur Cohn*

The spalling of steam-grown oxide from superheater and reheater tube steels
FP-686 Final Report (TPS76-655)

This technical planning study by Central Electricity Research Laboratories, England, examines world experience outside the United States on the spalling of steam-side oxide scale from austenitic and ferritic superheater and reheater tube materials, with special emphasis on the study of this problem being conducted in the United Kingdom.

The physical properties of the oxide scales are reviewed, and expansion coefficient data are used to estimate the cooling strains in the oxide for various alloys. Other contributory sources of strain are discussed, and models are presented for the failure behavior of oxide layers both in tension and in compression. A method of predicting quantities of debris release is described. The hydrodynamic behavior of spalled oxide flakes in steam circuits is considered analytically, and the conclusions are used to construct a method for assessing the risk of tube blockages. Attention is drawn to the effect of the debris particles' kinetic energy on wear rates of the eroded circuit components. In the concluding sections of the study, various palliative operation and design measures to prevent turbine erosion and tube blocking are examined, and areas requiring further study are highlighted. *EPRI Project Manager: Robert Jaffee*

Evaluation of sulfur-tolerant catalytic processes for producing peak-shaving alcohol fuels
AF-687 Final Report (TPS76-649)

The objective of this study by Catalytica Associates, Inc., was to determine the economic incentive for developing a sulfur-tolerant methanol synthesis catalyst.

Economic evaluations were performed on 10 conceptual methanol synthesis processes. Both once-through and synthesis gas recycle configurations were considered. Synthesis gas feeds with varied sulfur content were used. The literature and the industry were surveyed to ascertain the availability of such a sulfur-tolerant catalyst.

Little economic incentive was found for the development of such a catalyst. It was also found that there is no known sulfur-tolerant catalyst that has sufficient activity for commercial application. *EPRI Project Manager: Howard Lebowitz*

An assessment of the fuel cell's role in small utilities
EM-696 Final Report, Vols. 1 and 2 (RP918)

Fuel cell power plants are expected to have a number of unique features of potential benefit to small electric utility systems, including efficient operation, availability in small unit sizes, high reliability, a flat heat rate curve, minimal environmental impact, and a capability for dispersed siting. This study by Burns & McDonnell Engineering Co. assessed the role of fuel cells in small municipal and rural electric utility systems, identified the fuel cell characteristics most important for ensuring its successful penetration of the small-utility market, and quantified the value to small utilities of key fuel cell characteristics.

The fuel cell types evaluated in this study included a 5-MW first-generation fuel cell that operates on naphtha and 1-MW, 5-MW, 10-MW, and 25-MW advanced fuel cells that use No. 2 oil. The results of the study show good potential for the fuel cell to penetrate the small-utility market and compete with conventional generation from the baseload to the intermediate and peaking ranges of operation, especially if the characteristics specified for the advanced fuel cells can be achieved. Typical break-even capital costs ranged between $250 and $400/kW for the various scenarios. The major potential limitations on the use of these fuel cell types are oil availability and price. If the price of oil increases significantly faster than the price of other fuels in the future, fuel cell penetration may be restricted to peaking and intermediate-range operation. Since the study assumed that petroleum fuels would be available for small-utility generation, the risks associated with future oil availability would have to be separately factored into a small utility's analysis when weighing the potential benefits of fuel cells. *EPRI Project Manager: Arnold Fickett*

Gas extraction of a western subbituminous coal
AF-699 Final Report (RP779-1)

The British National Coal Board has developed a technique that uses supercritical fluids to obtain an extract from U.K. bituminous coals; this extract can be hydrocracked to yield a distillate oil rich in benzene derivatives and a reactive char suitable for gasification or combustion. No hydrogen is needed for the extraction; the need for wet filtration to separate the coal solution and the extraction residue is avoided; and there is virtually complete recovery of the solvent.

The technique has been applied in the laboratory to a high volatile, low-sulfur subbituminous coal from the western United States (Wyodak coal). A 20% yield of extract similar in composition (but lower in yield) to U.K. coal extracts was obtained by using supercritical toluene as solvent. The extract had a hydrogen content of 8% and a calorific value of 37,500 KJ/kg, compared with values of 5% and 29,500 KJ/kg for the coal. The char product was obtained as reactive free-flowing particles.

Extraction of the Wyodak coal with a supercritical paracresol-water mixture yielded approximately 40% extract, but decomposition of the paracresol occurred, giving rise to a further quantity of extract-like material. *EPRI Project Manager: Ronald Wolk*

NUCLEAR POWER

On-line power plant alarm and disturbance analysis system
NP-613 Interim Report (RP891)

This report documents the first task of a multitask project undertaken by Combustion Engineering, Inc., and Systems Control, Inc., to develop, implement, and demonstrate an on-line analysis procedure for power plant disturbances. The objective of such a procedure is to provide operating personnel with early recognition and diagnosis of plant disturbances and to recommend timely corrective action. This is expected to reduce the number of outages and therefore increase plant availability. Although the procedures to be developed will be applicable to the general process systems of a plant, the scope of the analysis and demonstration attempted in this project is limited to a representative set of disturbances in two plant subsystems. The report reviews the objectives and functional requirements for an on-line disturbance analysis system (DAS), the plant subsystems selected for analysis and demonstration, and the functional requirements and preliminary outline of the DAS design. Illustrative examples are cited, and some basic criteria for evaluating the DAS are highlighted. *EPRI Project Manager: A. B. Long*

A calorimetric measurement of decay heat from ^{235}U fission products from 10 to 10^5 seconds
NP-616 Final Report, Vol. 1 (RP230)

A calorimetric measurement of decay heat power of ^{235}U fission products has been made by the University of California at Berkeley, using a fast-response calorimeter in the cooling-time range from 10 to 10^5 s. The calorimeter is based on measurement of the rate of change of energy stored in a mercury absorber and on measurement of heat flow through a thermopile. Agreement between the measured values and summation calculations is good in the cooling-time range from 500 to 10^4 s. At less than 500 s, the accuracy potential of the instrument is not realized—the average of measured results is up to 17% higher than predicted. The estimated uncertainty of the measurement is 3.4% (one sigma) from 400 to 10^4 s and rises to 22.7% at 11 s. *EPRI Project Manager: Frank Rahn*

The calculation of the decay heat of fission products from exact relations
NP-616 Final Report, Vol. 2 (RP230)

This report by the University of California at Berkeley presents a solution method for the system of ordinary differential equations representing the concentration, activity, and decay heat of fission products. The method is based on a digital computer evaluation of the exact solution of the system expressed in recursive form.

The system of coupled differential equations describes the rate of change of the concentration of fission products resulting from direct production in fission, radioactive decay, and neutron absorption for 818 different nuclides. The decay heat is obtained by summing over the beta and gamma energies of each radioactive nuclide. The input nuclear data consist of fission yields, half-lives, branching ratios, and average energies of beta particles and gamma rays. *EPRI Project Manager: Frank Rahn*

Water entrainment in intercompartmental flow

NP-648 Final Report (RP275-1)

There are no models or correlations available that are useful for estimating entrainment rates in intercompartmental flows in nuclear containments. Calculations representing primary coolant breaks in PWR and BWR power reactors showed that the assumption of the extent of entrainment rate of the liquid phase in the exit flow had a significant effect on the predicted subcompartment pressure. Thus, the objective of this project by Drexel University was to develop a method of predicting entrainment rates. In a series of bench-scale tests, the effects of flow geometry and inlet fluid conditions on liquid-phase entrainment were determined for air-water mixtures flowing through a test section. In these tests, the most important variables were the test section's air velocity, air density, and instantaneous water volume fraction. The entrainment data were well represented as a function of average liquid volume fraction and superficial air mass flux flowing in a horizontal test section. Alternatively, predictions with a physical model of the entrainment process show good agreement with the measured entrainment rate for midrange superficial air mass flux values. *EPRI Project Manager: Gerald Lellouche*

Suppression pool swell analysis

NP-669-SR Special Report

The dynamic response of a Mark I pressure suppression system during the early air discharge phase of a postulated LOCA was studied mathematically by the University of California at Berkeley. The mathematical analysis of the surface swell caused by the initial discharge (located at a finite depth below the free surface) is described in detail, with the surface elevation shape as a function of time being one of the results. The initial approach considers the case of an infinite pool with the approach progressing to vertical boundary walls and finally to the semicircular pool cross section of the Mark I pressure suppression system. This analysis is valid for the time interval prior to any free surface impact. *EPRI Project Manager: Charles Sullivan*

Detailed analysis of the fundamental ultrasonic response data from stainless steel stress corrosion crack specimens

NP-676-SR Special Report (TPS75-620)

The development of improved ultrasonic testing techniques requires a study of the basic character of the reflected ultrasonic energy from an actual stress corrosion crack. Southwest Research Institute compiled considerable ultrasonic response data, using various combinations of inspection probes and instrument variables. The compiled results indicate a general direction for remedial action.

Consulting and laboratory facilities were provided by General Electric Co. through a joint cost-sharing program with EPRI. General Electric also provided the test samples used in the project. *EPRI Project Manager: Eugene Reinhart*

Analysis of some uranium oxide and mixed-oxide lattice measurements

NP-691 Final Report (RP830)

A series of critical lattice experiments has recently been carried out at Battelle, Pacific Northwest Laboratory's Plutonium Recycle Critical Facility (RP348). The experiments, which utilized both uranium oxide and mixed-oxide fuel (uranium-plutonium) moderated by clean or borated water, are expected to provide the information necessary for testing the accuracy of computer programs and nuclear data libraries used in the analysis of nuclear reactor cores.

In order for experimental information to be of value in such a validation program, it is necessary that uncertainties inherent in the measurements be quantitatively small. In general, experimental parameters such as reaction ratios or disadvantage factors (which can be compared with calculations) are not measured directly but must be deduced from foil activation data. Perturbations introduced by the measuring apparatus and effects of various other approximations must be determined and accounted for.

The objective of the present Stanford University project has been to provide a detailed and independent evaluation of the experimental procedures followed in RP348 and of the correction factors that have been applied. The revised "measured" parameters are compared with calculated values obtained from the most rigorous neutronic analysis methods. The proposed corrections and revisions to the measured values have indicated the advisability of supporting such reviews in parallel with experimental programs. The revisions to the measured parameters are expected to extend the usefulness of the results obtained in RP348. *EPRI Project Manager: Odelli Ozer*

Comprehensive study of the operating and testing experience during the startup and initial operation at the Fort St. Vrain HTGR: phase I

NP-697 Key Phase Report (RP457-1)

The Phase I report by The S. M. Stoller Corp. documents the important experience gained at the Fort St. Vrain HTGR plant during the performance of preoperational tests. Also documented are general experiences from the start of preoperational testing to the commencement of the rise-to-power tests in April 1975. This is the first of three phase reports. The analysis of experiences at Fort St. Vrain may be of value in the design, construction, and operation of future gas-cooled reactors. The report also contains summary descriptions of the various Fort St. Vrain plant systems for use in interpreting the discussions contained in all three phase reports. *EPRI Project Manager: James Kendall*

Comprehensive study of the operating and testing experience during the startup and initial operation at the Fort St. Vrain HTGR: phase II

NP-698 Key Phase Report (RP457-1)

The Phase II report by The S. M. Stoller Corp. documents results from the formal core loading, physics, and low-power testing program at the Fort St. Vrain HTGR plant (December 1973–November 1974). It covers the following operations performed during the low-power startup tests: initial loading of fuel and reflector elements; core reactivity, reactivity coefficient, and control rod worth measurements; nuclear flux distribution measurements; control rod drive and helium flow orifice valve performance; fuel-handling equipment performance; helium purification system performance; and helium circulator performance. *EPRI Project Manager: James Kendall*

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