Managing Nuclear Waste

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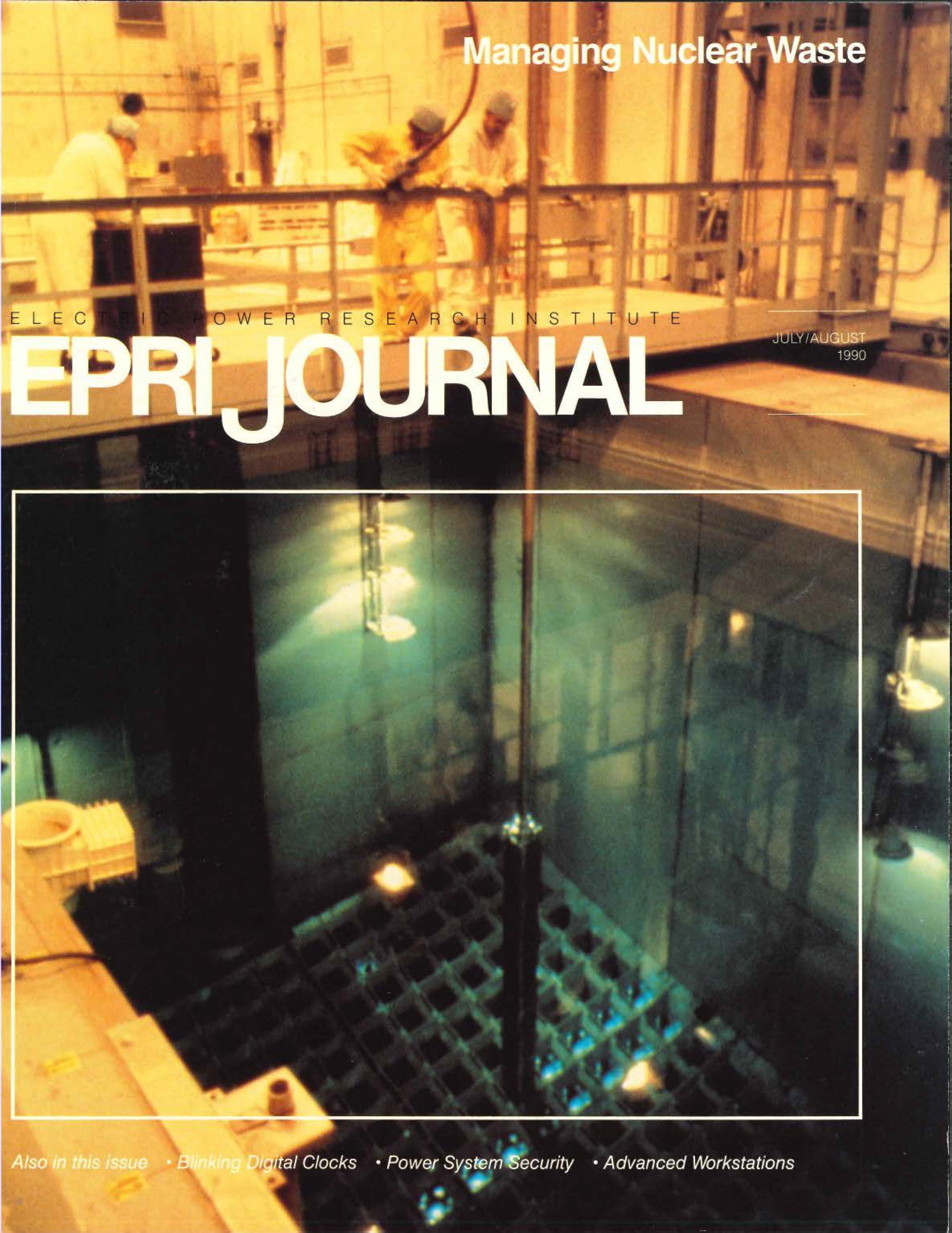

Also in this issue • Blinking Digital Clocks • Power System Security • Advanced Workstations

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Cover: Spent-fuel pool at Prairie Island nuclear power plant in Minnesota. (Photo courtesy of Northern States Power.)

Leveraging the Industry's Stake in High-Level Waste Disposal

Over much of the last year, EPRI has been developing a methodology that we hope will save utilities and electricity consumers perhaps millions of dollars and lead to an early determination of the suitability of Yucca Mountain, Nevada, as the site for an underground high-level radioactive waste repository. We are developing an alternative, probabilistic approach to the scientific assessment of Yucca Mountain that would take less time and cost less than the comprehensive site characterization currently under way by the Department of Energy, the agency responsible for the federal high-level nuclear waste program. DOE's plans to scientifically study Yucca Mountain have been stalled by political roadblocks in Nevada.

We believe our methodology has the potential to be accepted by federal regulators, by DOE, and by Nevada state authorities as a scientifically sound and credible approach to reaching an expedited decision about Yucca Mountain. The methodology integrates the judgment of a wide range of technical experts to reveal critical uncertainties and to focus on high-priority site investigations with a significant impact on the probabilistic evaluation of the candidate repository site. We intend to demonstrate the methodology to all interested parties by the end of this year and then provide DOE the opportunity to implement the central concepts as its approach to the early assessment of the suitability of Yucca Mountain. The general methodology includes no preconceptions or foregone conclusions about this site.

EPRI's effort is highly leveraged: it involves current-year spending of about $1 million in reallocated R&D budget and supplemental industry funds. DOE is currently spending $250 million a year from the nearly $5 billion Nuclear Waste Fund, a fund paid for by consumers through utilities to evaluate a site for and provide a high-level waste repository. Federal expenditures to date total about half of the funds collected by utilities (plus interest accrued) so far under the 1982 Nuclear Waste Policy Act.

We were asked to take on this activity by ACORD, the American Committee on Radwaste Disposal, a top utility executive oversight group coordinating the industry's interface with the federal high-level waste program. The Edison Electric Institute is coordinating the technical effort by EPRI, with related support from the American Nuclear Energy Council, the Nuclear Management and Resources Council, and the U.S. Council for Energy Awareness. In addition to the repository assessment methodology, the cooperative effort includes work to demonstrate, and obtain regulatory acceptance of, a variety of casks and modules for on-site spent-fuel storage and transport.

As a nation and as citizens of individual states, we must come to terms with the fact that some place eventually must serve as the site of a nuclear waste repository if we are to be environmentally responsible in dealing with the waste from an important energy resource. EPRI hopes to make a crucial contribution on behalf of the electric utility industry toward that ultimate goal.

Abdon Rubio, Director
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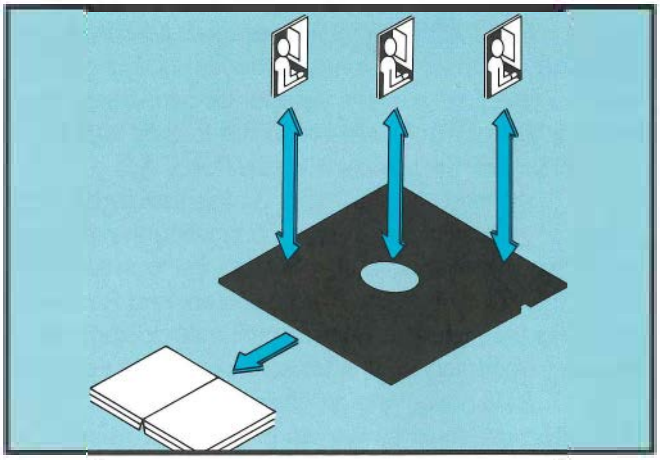

DEPARTMENTS

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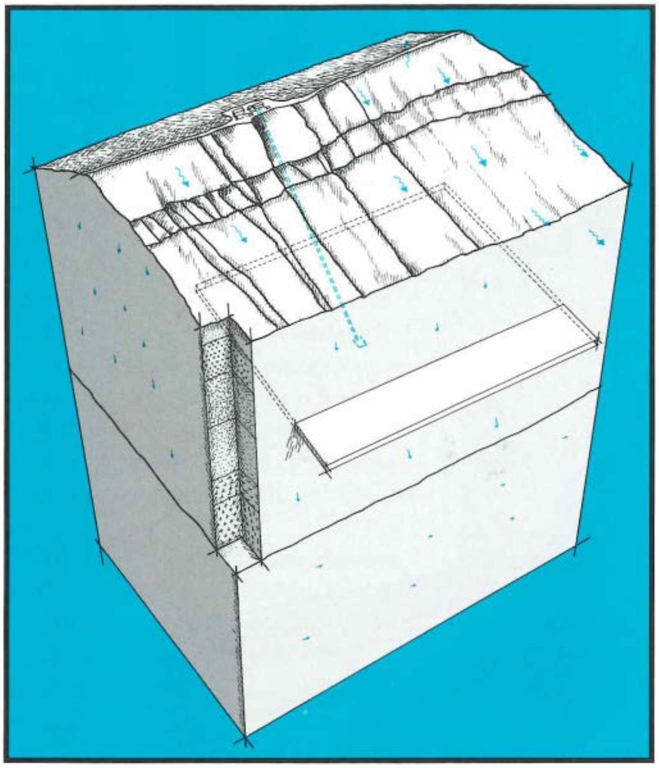

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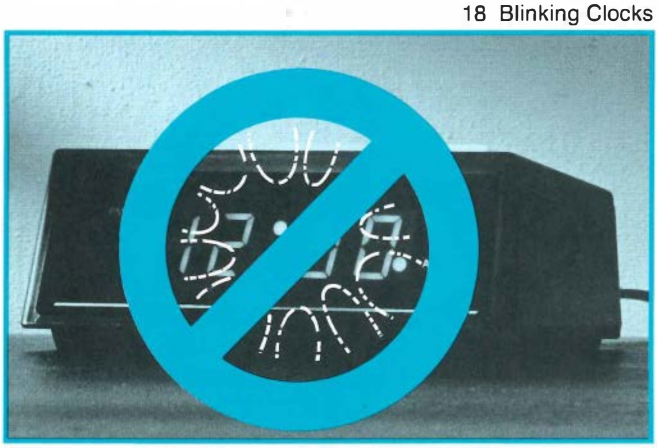
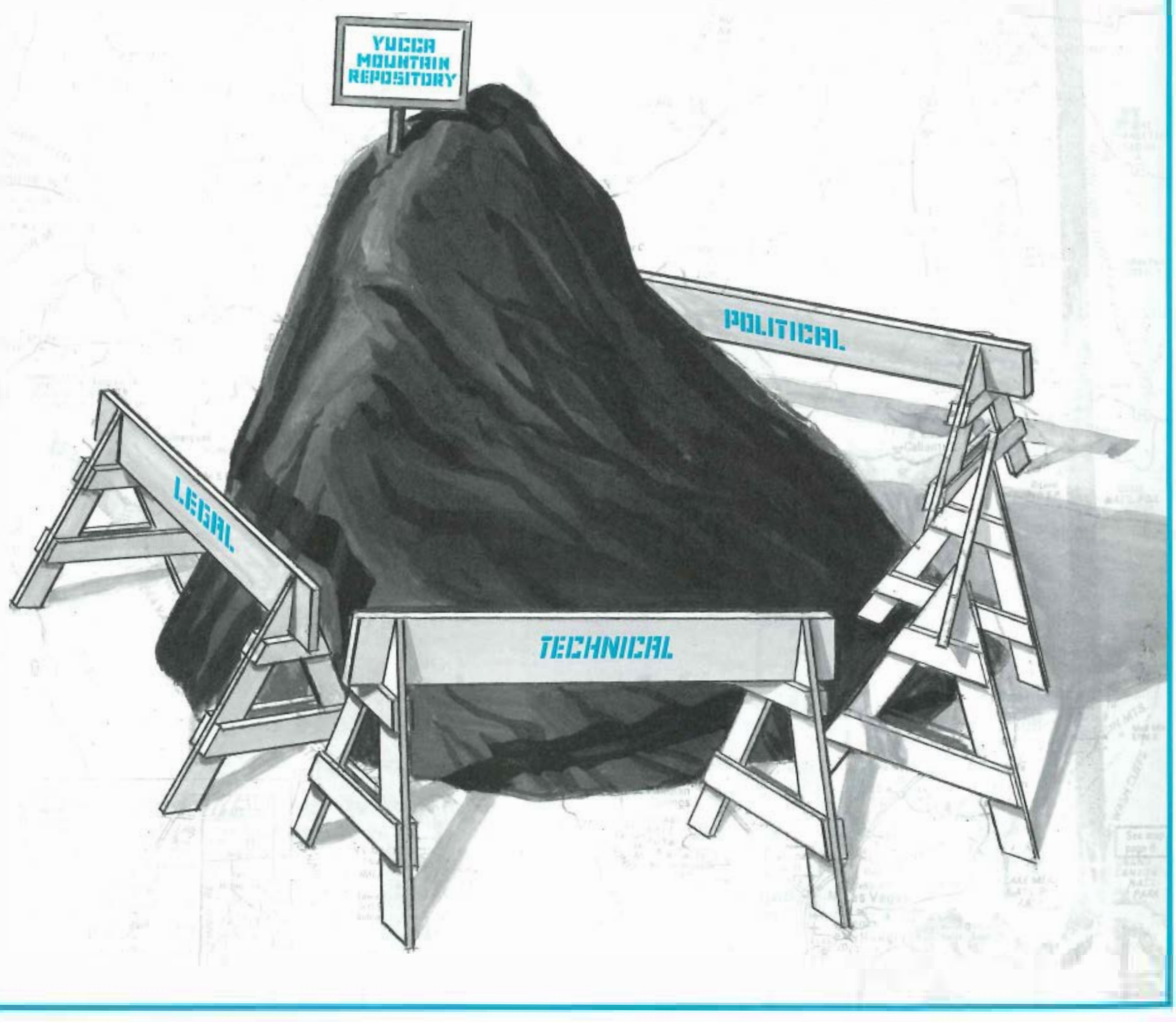


THE HARD ROAD TO NUCLEAR WASTE DISPOSAL



Providing for the safe disposal of spent fuel from commercial power reactors has been recognized as a national responsibility since utilities first joined with the federal government in the development of nuclear power technology in the 1950s. In the last decade, recognition of this responsibility took the form of a national commitment to resolve the nuclear waste issue by the end of the century. Since 1982, electricity consumers have paid a one-tenth-of-a-cent fee on every nuclear-generated kilowatthour for eventual waste disposal. Payments and interest credited to this fund currently total nearly $5 billion.

But the government now says that, despite having already spent about half of the money collected so far, because of political, legal, and technical delays it cannot begin operating a permanent repository for high-level radioactive waste by 2003 as it had earlier estimated—let alone by 1998, the date set by Congress eight years ago. As a result, utilities face a deepening quandary.

With storage pools at many reactors nearing capacity, some utilities have begun providing for interim dry storage of spent fuel at the power plants, using metal casks and concrete modules demonstrated with EPRI and government support. Most utilities have already reracked storage pools to hold more fuel, and consolidation of fuel rods for even closer spacing has been demonstrated. Meanwhile, pressures are increasing again for an interim federal storage facility where spent fuel could be temporarily held until a final repository is opened.

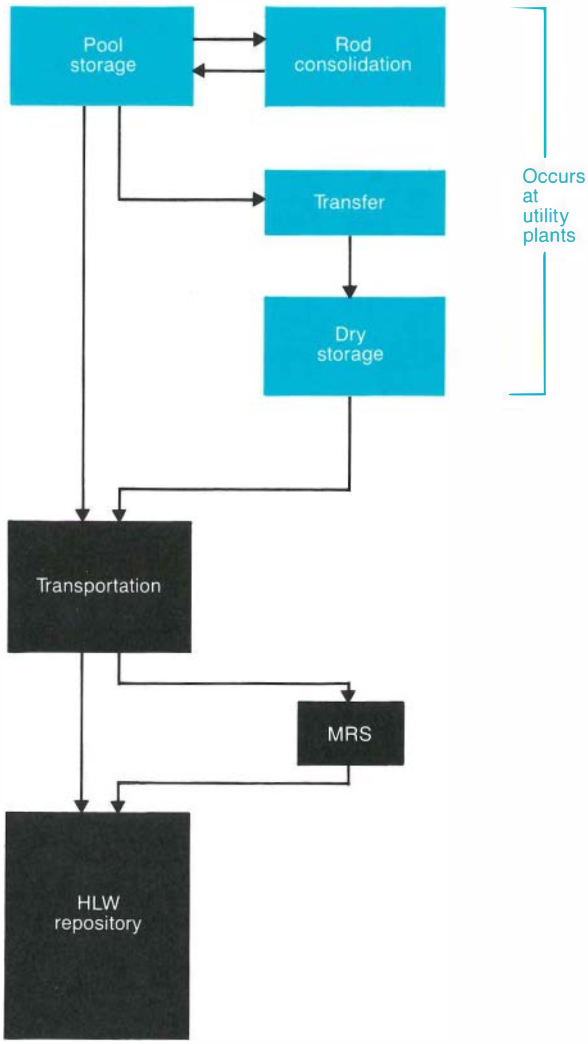
Citing its own lack of progress in determining the suitability of the congressionally designated candidate repository site at Yucca Mountain, Nevada, the Department of Energy last November revised its estimate for an opening date to 2010 at the earliest. By then, the number of nuclear plants with more spent fuel than their storage pools can hold is expected to have increased to about 80,

THE STORY IN BRIEF

Resolving the nuclear waste problem is critical to the future of nuclear power, but political, legal, and technical delays have put off the opening date for a permanent, government-operated high-level waste repository until at least 2010. For utilities, the need to add to spent-fuel storage capacity is becoming increasingly urgent: storage pools at some nuclear power plants are already filled to capacity, and about three-quarters of today's operating plants will face this dilemma over the next 20 years. While continuing to assist in the demonstration of dry storage technologies for interim on-site spent-fuel management, EPRI has also launched a project that could help expedite site suitability studies for the candidate permanent repository at Nevada's Yucca Mountain. Expanding a decision-modeling framework developed by EPRI for seismic hazard research, the project will outline an effective technique for identifying and assessing the key geotechnical issues at the site.

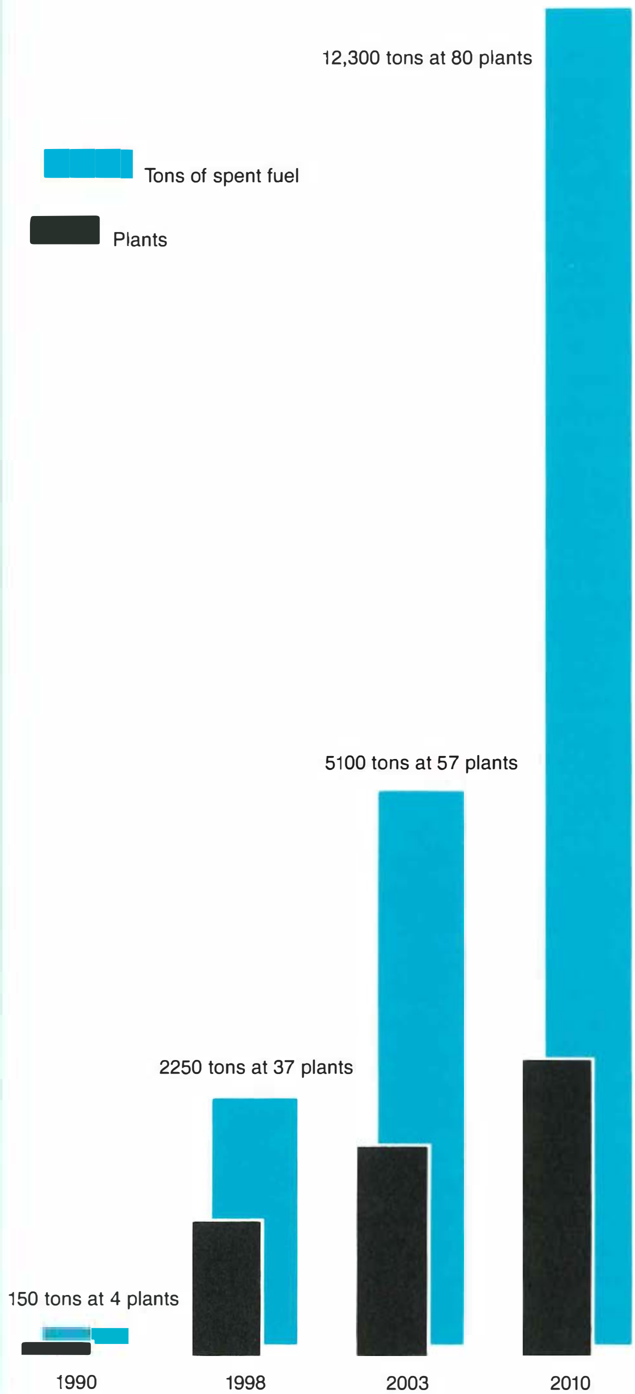
Spent Fuel and High-Level Waste: An Overview

The diagram shows principal activities and proposed facilities for the management of spent reactor fuel. At nuclear power plants, utilities first store fuel discharged from reactors in deep pools of water. When a permanent, underground high-level waste repository is chosen and opened, spent fuel will be shipped directly from utility plants in special casks. To fill the gap in storage before a repository opens, an aboveground, interim monitored retrievable storage (MRS) facility has been proposed that would permit the federal government to begin accepting spent fuel from utilities in 1998. Meantime, several utilities have transferred spent fuel from storage pools to dry metal and concrete casks and modules in order to maintain an operating reserve of pool storage capacity. Another option demonstrated for regulatory acceptance is to disassemble fuel and consolidate fuel rods for closer spacing in the storage pools.



How the Need for Spent-Fuel Storage Will Grow

The number of nuclear plants with spent reactor fuel that cannot be accommodated in storage pools and the volume of fuel requiring dry storage are expected to increase sharply over the next two decades.



compared with 4 today. The amount of fuel that is beyond the capacity of utilities' storage pools and must be stored in new, on-site dry storage systems is projected to increase from around 150 metric tons currently to over 12,000 tons by then.

"The announced delay to 2010 in completing a final repository is driving utilities to provide interim on-site storage of spent fuel," explains Robert Shaw, senior program manager for high-level waste in EPRI's Nuclear Power Division. "But the prospect of paying more than once for storage and disposal is not sitting well with utilities. So while we have been assisting in the demonstration of dry storage technologies, EPRI has also launched, at the request of the industry, an effort to try to help move along the site suitability assessment at Yucca Mountain."

In a coordinated effort involving a number of industry groups, EPRI is beginning to play a key role in developing an expedited approach to assessing the suitability of Yucca Mountain as a high-level waste repository. A decision analysis methodology being adapted from earlier EPRI seismic hazard assessment research is expected to help DOE identify and assess the critical hydrologic and geotechnical issues and uncertainties most important to resolve at Yucca Mountain. Field studies at the site are presently on hold, pending resolution of a federal court battle between DOE and the state of Nevada, which has refused to issue the needed permits.

"Utilities are very concerned that the technical approach DOE is taking may not lead to an early identification of the critical factors affecting the acceptability of the site," adds Shaw. "They feel that a more focused approach to site suitability assessment must be pursued if the new 2010 target completion date is to be met, and this is the objective of EPRI's work."

Critical for future of nuclear power

Having a plan and a system for dealing with spent fuel has always been considered essential for the long-term viability of the nuclear option. As high-level waste policies and plans have evolved over the last three decades, there have been numerous major changes. Until the late 1970s, it was assumed that spent uranium oxide fuel would be chemically reprocessed to separate waste isotopes from the by-product plutonium and unburned uranium that could be used to fuel future breeder reactors. The concentrated fission products would be mixed with glassmaking materials to form a highly corrosion-resistant solid borosilicate waste that would be buried deep underground in suitable geologic formations.

But concerns that fuel reprocessing could also increase the potential for the spread of nuclear weapons prompted a policy, first announced by President Carter in 1977, that America would indefinitely defer fuel reprocessing. Instead, the president decided that, for the time being, the country would permanently dispose of spent fuel rods in sealed steel canisters in an underground repository. Subsequent reconsideration of the economics and logic of reprocessing has not changed the outlook for that option in the United States, despite its use in some other countries.

The original federal agency responsible for implementing a nuclear waste disposal program, the Atomic Energy Commission (a predecessor to DOE), had planned in the 1960s to build an underground repository in a cavernous Kansas salt mine. But the site proved to have significant uncertainties and the search moved elsewhere. As the installation of nuclear generating plants expanded in the 1970s, the need for a credible waste disposal plan and visible progress toward an operating repository became a key issue in the larger debate over nuclear power.

In the 1980s, administration and congressional leaders forged a legislative package that was hailed as a comprehensive solution to the high-level nuclear waste problem. The Nuclear Waste Policy Act (NWPA) of 1982 instructed DOE to plan for two national waste repositories. Most of the candidate sites studied up to that time were in the West, so the subsequent search for a second repository site was centered in the Midwest and the East, which was as much a matter of regional equity as an attempt to minimize spent-fuel shipping costs.

In amendments to the nuclear waste act passed in 1987, however, after DOE had narrowed its list of candidates for the first repository to three geologically very different sites—in Nevada, Texas, and Washington—for extensive characterization, Congress and the administration suspended site screening work for a second repository. This was in large part because of political opposition in the eastern states where candidate sites had been identified and also because of soaring estimates of the cost of characterizing multiple sites. As some analysts have noted, the political opposition that developed to the three western sites was greatly intensified by the abandonment of the search for an eastern site, which upset a fragile political compromise embodied in the 1982 waste act.

Two of the western sites chosen for detailed study were on or near large remote expanses of federal land long ceded to the government's use. These were the basalt rock that underlies DOE's Hanford nuclear reservation in Washington state and the volcanic tuff of Yucca Mountain, near DOE's Nevada nuclear weapons test site. The third possible site was a massive underground salt formation in Deaf Smith County, Texas, in panhandle ranch country.

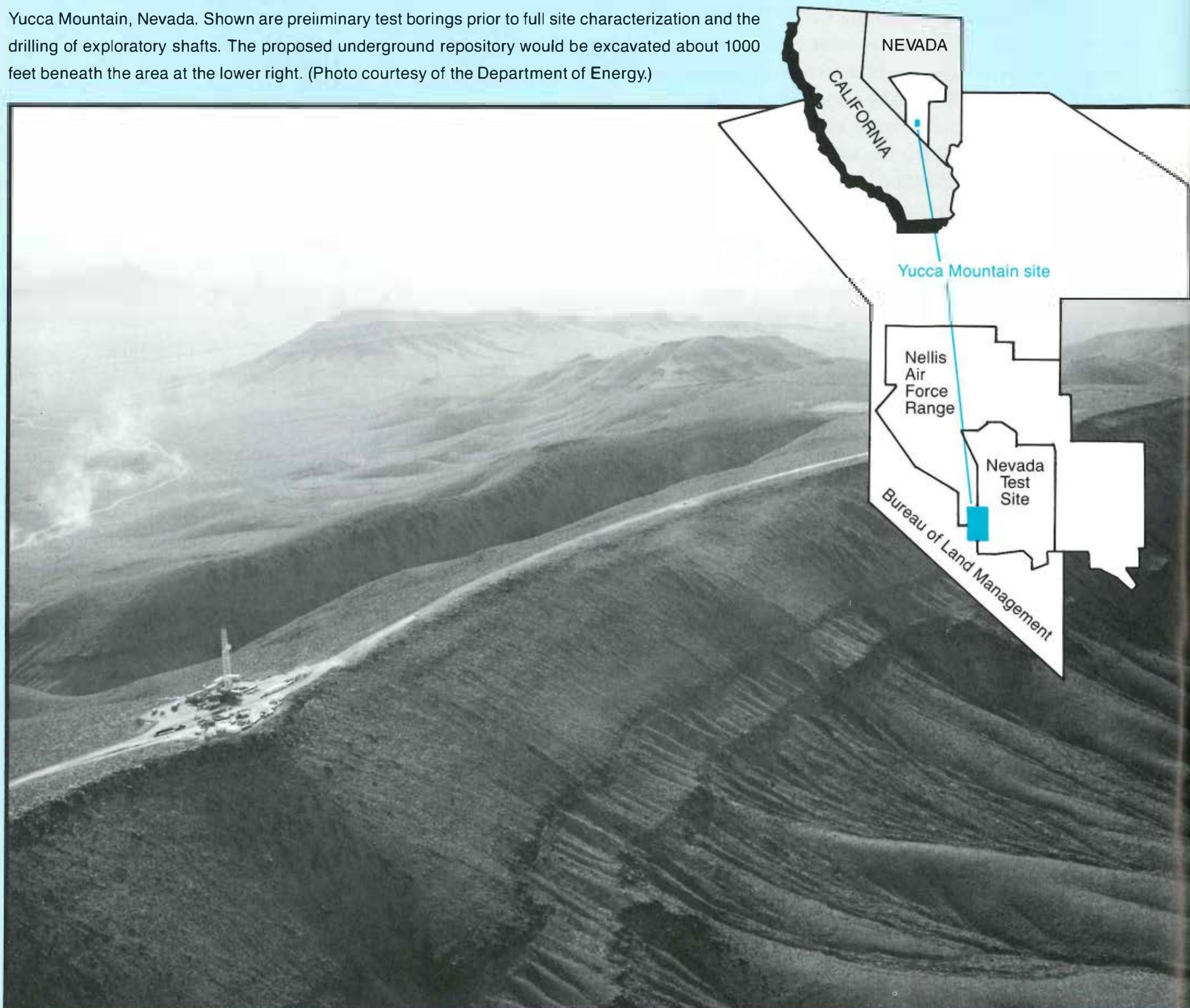
In the months after the three candidate sites were named, the pros and cons of each were aired locally, regionally, and often nationally. At Hanford, the generally enthusiastic, willing area populace has been long accustomed to the presence of nuclear industry; nevertheless, the site's complex groundwater network and its proximity to the Columbia River,

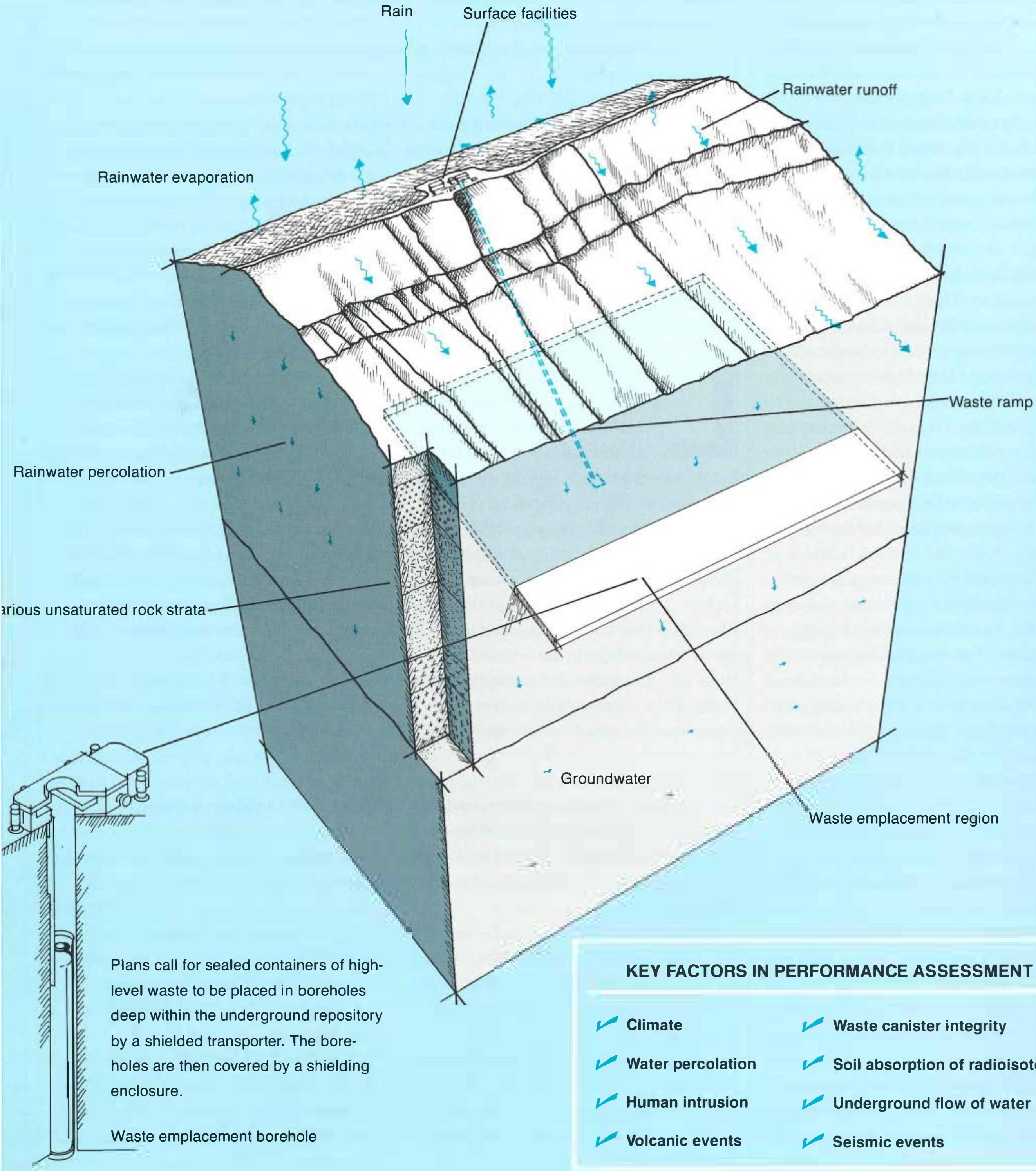
An Overview of Yucca Mountain

Yucca Mountain, Nevada, 100 miles northwest of Las Vegas, is the congressionally designated site for a permanent high-level nuclear waste repository, contingent upon detailed geotechnical characterization by the Department of Energy, a positive DOE recommendation, and a presidential nomination of the site. But site characterization work is on hold because Nevada state authorities have not issued the required air quality permits. Upon resolution of the current legal impasse between Nevada and the federal government, scientific studies and experiments at the site will seek to resolve geotechnical uncertainties surrounding its suitability as a permanent nuclear waste repository.

Some features of the site make it particularly attractive as a waste repository. It has an arid climate, favorable soil features, and a very low water table with groundwater that travels very slowly. But other aspects of Yucca Mountain raise questions about its suitability: three principal areas of inquiry involve the very long term potential for volcanism, seismic activity, and climate change to alter groundwater flow patterns beneath Yucca Mountain. Such changes could affect the performance of some components of the waste repository in containing the release of radionuclides into the environment via groundwater.

Yucca Mountain, Nevada. Shown are preliminary test borings prior to full site characterization and the drilling of exploratory shafts. The proposed underground repository would be excavated about 1000 feet beneath the area at the lower right. (Photo courtesy of the Department of Energy.)





Plans call for sealed containers of high-level waste to be placed in boreholes deep within the underground repository by a shielded transporter. The boreholes are then covered by a shielding enclosure.

KEY FACTORS IN PERFORMANCE ASSESSMENT

- **Climate**
- **Water percolation**
- **Human intrusion**
- **Volcanic events**
- **Waste canister integrity**
- **Soil absorption of radioisotopes**
- **Underground flow of water**
- **Seismic events**

coupled with past leaks of high-level defense wastes on the reservation, made that site problematic. On the other hand, few West Texans favored the Deaf Smith County site because of concerns about the underlying Ogallala aquifer, which supplies nearly all the water in the seven-state High Plains region.

Of the three sites, many analysts considered Yucca Mountain the most technically attractive. It has an arid, desert climate, favorable soil features that would tend to retard the movement of radionuclides, and a water table that is some 1000 feet below the proposed 1000-foot-deep repository. Moreover, the remote site 100 miles northwest of Las Vegas—near where hundreds of underground nuclear weapons tests have occurred—seems unlikely to ever be of value for another purpose. The artificial seismic activity from weapons tests would not be expected to significantly affect the underground repository but would impose certain design considerations for the repository shafts and surface facilities.

But the area is also seismically active, and its many different geologic strata are intersected by several faults. Despite groundwater that is quite deep and moves exceedingly slowly, the local hydrology is nonetheless complicated and not completely understood. There is also evidence of nearby volcanic activity within geologic periods of time relevant to a repository's 100,000-year containment design. Both volcanic and seismic activity potentially could alter groundwater flow patterns and the level of the water table.

In a move by Congress intended to focus expenditures from the consumer-paid Nuclear Waste Fund by reducing the number of sites to be studied, the 1987 Nuclear Waste Policy Act Amendments designated Yucca Mountain as the first candidate repository site for characterization. Several of the national laboratories under DOE set about planning a full-scale, multidisciplinary site characterization program for Yucca Mountain. The waste act amendments established a multimillion-dollar benefits and impact assistance package to be provided to Nevada over the life of the repository if the characterization proved favorable and Yucca Mountain was designated as the repository site.

At the time, the 1987 amendments were widely seen as evidence that the federal government was getting a handle on the high-level nuclear waste problem. In recognition of earlier delays, the schedule was adjusted and 2003 was set as the new goal for opening a repository, which would hold not only spent reactor fuel but also high-level nuclear wastes from defense production.

Local and state political and media reaction to the designation of Yucca Mountain, however, has been extremely negative. Ever since the search for a repository site was narrowed to one candidate, Nevada's governor and other political leaders have fiercely criticized DOE's political handling of the site selection process and its technical work to demonstrate that Yucca Mountain is suitable. Moreover, state earth science experts have raised questions about features of the site that they claim make it unsuitable, in certain worst-case scenarios, under the conditions specified in the 1987 waste act amendments. Nevada has refused to issue air quality permits for DOE to drill an exploratory shaft at Yucca Mountain—the next step in site characterization—saying its legislature has already refused to host the repository.

Nevada has sued in federal court to block DOE's plans to study Yucca Mountain, and DOE has countersued to force the state to process its permit request. Citing the NWPA and amendments, the federal government says that the state of Nevada cannot preemptively refuse to host a repository unless and until the site is judged suitable and is nominated by the president. Congress could still override a state's veto.

A 10,000-year regulatory standard?

Comparisons and contrasts are often drawn between DOE's experience in trying to site a high-level waste (HLW) repository and its experience with another underground repository, for transuranic (mostly plutonium) defense wastes, at the Waste Isolation Pilot Plant near Carlsbad, New Mexico. WIPP, nearing completion after some 15 years in development and expected to begin operational tests within the next year, has been built in an underground salt formation. (One of the attractive features of salt formations for waste burial is salt's slow creep over time, which tends to seal up excavations into it.)

Although transuranic waste is typically long-lived (plutonium's half-life is 24,000 years), considerably less-intense radiation and heat are involved with this type of waste than with spent reactor fuel; a result is somewhat less-demanding repository design requirements at WIPP. But significant uncertainties surround various aspects of possible geohydrologic and climate conditions that may occur over the very long design containment period. Much of the delay in opening WIPP has involved analysis of such risks and uncertainties and design modifications to reduce them.

But there are two important contrasts between WIPP and the proposed HLW repository. The public generally has been more accepting and supportive of the New Mexico project, with its politically different origin and history. This has been, in part, the result of a 1977 agreement betweeen DOE and the state. Moreover, some observers have taken the position that, because of the different nature of the waste and the site, there is less of a challenge posed by WIPP's scale, design features, and performance criteria than is the case with an HLW repository.

Part of the reason for some of the controversy surrounding the proposed HLW repository at Yucca Mountain, however, is the uncertainties involved in designing

Key Players in the High-Level Nuclear Waste Repository Drama

At a glance, here are the major institutional parties with a stake in the national program to develop a permanent high-level nuclear waste repository.

Utilities are currently responsible for spent-fuel storage under NRC regulation. Contracts with the Department of Energy call for DOE to begin receiving spent fuel in 1998. Four utility plants have already exceeded storage pool capacity and have installed or are installing on-site dry storage casks or modules.

Department of Energy bears statutory responsibility for implementing the Nuclear Waste Policy Act and amendments. It is awaiting resolution of the legal impasse with the state of Nevada in federal court to begin detailed scientific study of Yucca Mountain to assess its suitability as a repository site. DOE is responsible for developing, obtaining license approval, and operating the waste repository.

Nuclear Regulatory Commission defines licensing requirements for repository performance and fuel transportation on the basis of EPA environmental criteria. After the licensing and completion of a site, NRC would also monitor waste burial operations for regulatory compliance.

State of Nevada legislature has preemptively declined to host a high-level waste repository. The governor and other political leaders are strongly opposing the federal repository program. Nevada authorities have refused to issue DOE an air quality permit to conduct site studies at Yucca Mountain. The state has sued DOE to block plans for determining the site's suitability as a repository.

Environmental Protection Agency sets the groundwater protection standards on which NRC regulations for repository performance are based. It sets maximum permissible concentrations for key radionuclides in groundwater at the site boundary after 1000 and 10,000 years.

U.S. Congress established the legislative and statutory basis for a repository program in the 1982 Nuclear Waste Policy Act and the 1987 amendments. It designated Yucca Mountain as the candidate repository site, pending detailed characterization, and directly oversees DOE's efforts to implement the waste laws.

The courts, mainly at the federal level, may have to resolve what is shaping up as a classic federal-state legal battle over which government has the ultimate authority over the use of federal land for a national nuclear waste repository.

Other states may become involved in the drama as the federal government searches for a state willing to host an interim monitored retrievable storage facility. Such an aboveground MRS facility may be essential if DOE is to keep its commitment to begin accepting spent nuclear fuel from utilities in 1998.

for that site and analyzing whether it can meet Nuclear Regulatory Commission licensing criteria, as required by the nuclear waste act. The criteria are based on 1000-year and 10,000-year repository safety and environmental protection standards independently defined by the Environmental Protection Agency.

Presently being revised by EPA under court order as a result of a lawsuit brought by environmentalists, the standards specify maximum permissible off-site concentrations in groundwater of key radionuclides after 1000- and 10,000-year periods, based on probabilistic estimates of repository containment. Related NRC regulations specify the required performance of both engineered and natural components of the multibarrier repository system. In the analysis of a proposed site's ability to comply with the standards, models of the component processes that theoretically could lead to off-site release of radioactivity are linked and integrated in a probabilistic risk assessment.

According to Robert Williams, a technical adviser in EPRI's high-level waste program, the off-site release limits for 10,000 years inferred from the EPA performance standards are 10 times more stringent than those that presently apply to nuclear reactors. The related permissible radiation health risks are 1000 times tighter than existing public health standards.

"The regulatory and safety and environmental criteria are at the heart of what is driving the overall scope, the amount of time required, and the cost of characterizing Yucca Mountain, whenever site work resumes," says Williams. "So in addition to our efforts to develop a methodology that might help DOE make an early site suitability assessment, we're also addressing the regulatory dimension on a technical level. After site characterization work, at some point DOE has to go to the regulator and say it has enough data to show that particular criteria can be met. The methodology and process EPRI is developing will help show how much data is enough to reasonably prove that site performance can meet regulatory standards."

As Williams notes, although actual licensing activity for a repository would not begin for many years, the evolving EPA and NRC regulatory standards are central to even preliminary evalutions of the Yucca Mountain site, as well as to considerations of the repository design. "The calculations that are the basis of many of the regulatory criteria for repository performance have so much conservatism built into them that it becomes very difficult to prove that, 10,000 years out in the future, off-site releases would be below the very low limits specified," adds Williams. Part of EPRI's involvement on behalf of utilities in the site assessment at Yucca Mountain may include review of the criteria and of how additional engineering features might be incorporated in the repository design to reduce uncertainties over the facility's projected ability to satisfy certain criteria.

Despite the attractive features of Yucca Mountain, the site's geotechnical complexity and potential for faulting and climate change over the life of a repository raise questions about its suitability. And they make evaluation of the site with the kind of certainty usually expected in licensing proceedings extremely difficult. "The analytic challenge is unprecedented," says Williams.

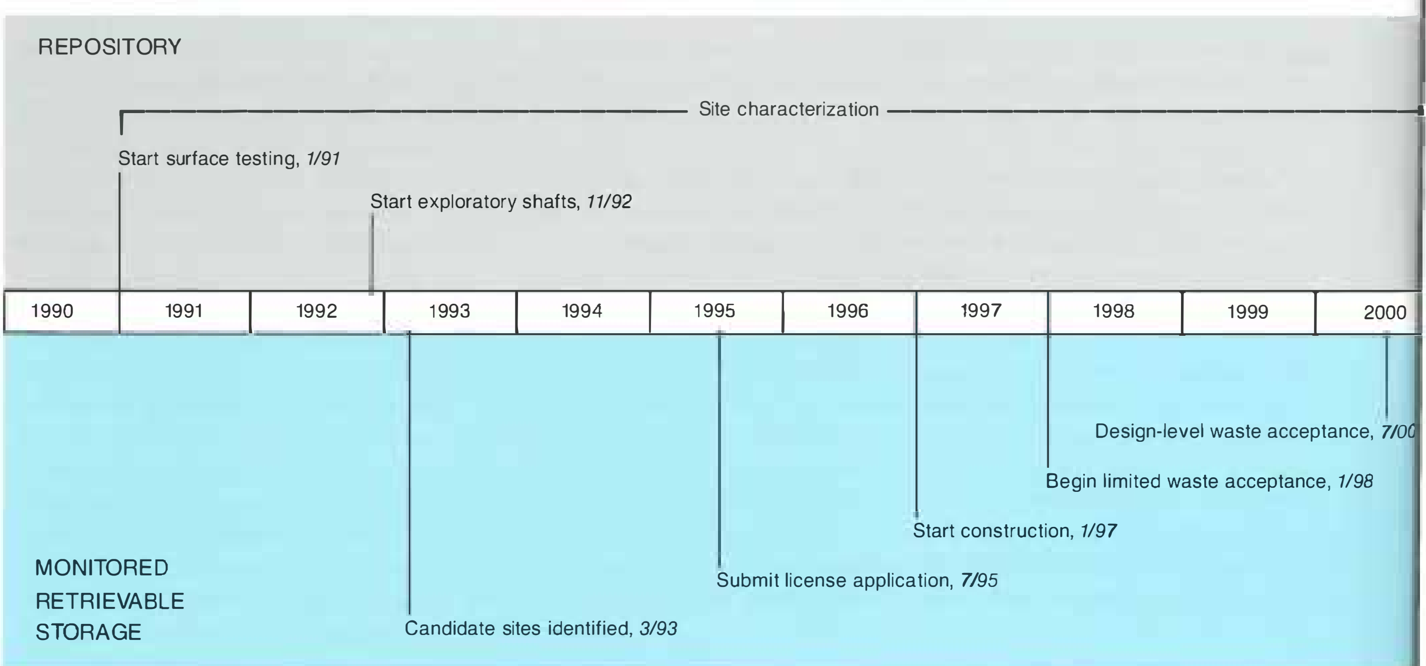
Says Shaw: "DOE's earlier site characterization plan for Yucca Mountain was not an explicit, continuing evaluation of site suitability but was instead a comprehensive, unprioritized, bottom-up approach to a state-of-the-art geotechnical assessment as the way to deal with the site's geologic complexity. The plan was to consider overall suitability only after field studies were completed and all the major geotechnical issues had been evaluated individually."

When DOE last November revised its target completion date for the repository to 2010, department officials said that an already-drafted nine-volume site characterization plan would require several more years to be implemented. They said a new plan would be drawn up that was geared to an earlier determination of site suitability. The new director of DOE's Office of Civilian Radioactive Waste Management, John Bartlett, has promised major changes in the federal program and specifically in DOE's approach to site characterization at Yucca Mountain. Prior to his federal appointment earlier this year, Bartlett was with the Analytic Sciences Corp., a nuclear engineering firm, and he has many years of experience in the nuclear waste field.

Bartlett told an international conference on high-level waste management last April that one of his principal goals was "to determine, as soon as possible, whether or not the Yucca Mountain site

Key Milestones in the Nuclear Waste Program

This timetable shows major points in the federal government's program for opening a permanent high-level waste repository and for an aboveground, interim MRS



is suitable for a repository. This is the first major milestone along the path leading to disposal. To meet this goal, we will establish and pursue a focused, prioritized site evaluation program endorsed by external peers." Bartlett continued, "We will also pursue timely development of suitability evaluation methods and criteria. The criteria will be developed by others and the evaluation methods will receive external peer review."

EPRI and other observers have estimated that a realistic restructuring of the program and comprehensive characterization will take 10–12 years. After that, DOE would make a recommendation on suitability and, if the site were nominated, submit a license application to NRC. The licensing review process is realistically expected to require another 6–8 years.

EPRI became involved at the research and technical level of the repository assessment activity in 1989 at the request of ACORD, the American Committee on Radwaste Disposal, a utility executive group that oversees an integrated industry response involving several organizations. EPRI's activity is closely coordinated with and partly supported by the UWASTE group of the Edison Electric Institute, which is responsible for program and technical analysis and regulatory interface. Other utility organizations include the American Nuclear Energy Council, the Nuclear Management and Resources Council, and the U.S. Council for Energy Awareness.

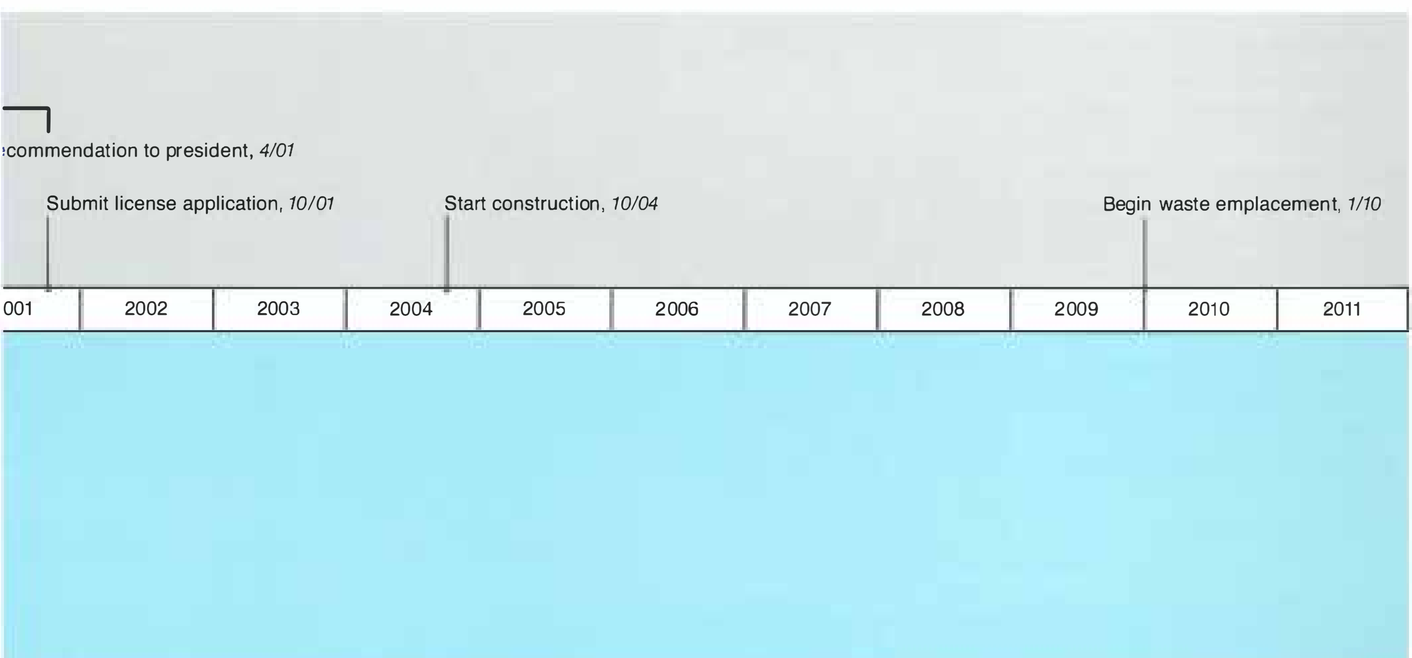
"We are in the process of developing an approach that we feel will help DOE come to a determination about Yucca Mountain much sooner," Shaw adds. "If the site does prove to be unsuitable, the policy and legislative decision makers need to know as soon as possible so that adjustments can be made and alternatives to Yucca Mountain can be considered, if necessary. Time is very much of the essence, despite the number of years involved."

Site methodology development

What EPRI hopes to contribute to the characterization effort at Yucca Mountain is a modeling-based methodological approach that DOE could use to analyze site suitability in an integrated, but expedited, way. The approach would highlight the key geotechnical uncertainties about the site with the greatest influence on calculations of various risks and would identify and prioritize the necessary technical data most critical to resolving those uncertainties.

"We're developing a decision framework for making these calculations and tying things together in a more flexible, top-down, prioritized and focused approach to site assessment," explains Shaw. "We look to DOE to be extensively involved in the actual implementation of the methodology."

ıcility. The estimated dates assume no additional major political or legal delays.



The methodology is based on an open decision-modeling approach previously applied in EPRI projects involving complex issues, including acid rain and other types of risk analysis. It attempts to reach a consensus among the interpretations of various technical experts. Specifically, the approach is being adapted from a seismic hazard assessment methodology developed by the Nuclear Power Division. Embodied in the EPRI computer code EQHAZARD, the seismic methodology was a pioneering form of risk assessment for earthquakes at eastern nuclear plant sites that was accepted by NRC for utility use in safety evaluations.

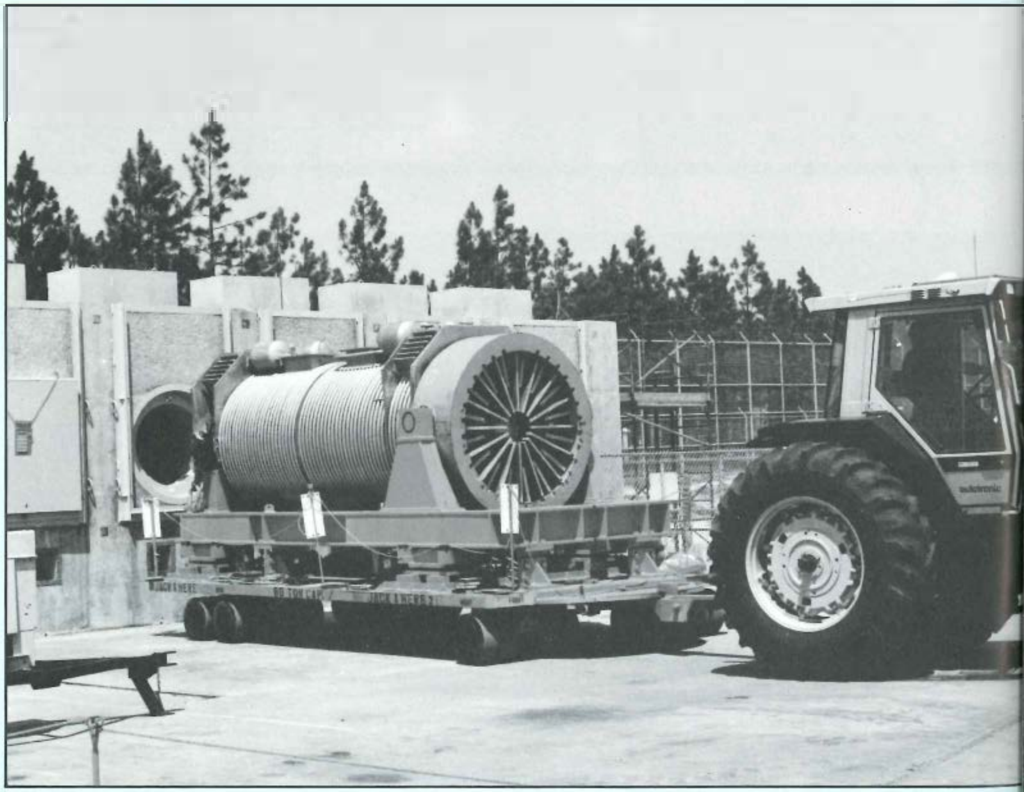
According to J. Carl Stepp, an EPRI senior program manager, a former chief of geosciences at NRC, and a principal figure in the development of the seismic hazard methodology, the approach is "basically a method of incorporating within a probabilistic computational structure the subjective assessments of alternative interpretations of geologic phenomena that are poorly understood. In a nutshell, it involves modeling competing interpretations in a logic-tree structure."

Following the approach used in developing the seismic methodology, for the waste repository site assessment EPRI has assembled a team of experts in the various scientific disciplines (hydrology, geochemistry, seismology, climatology, and so on) with a mutual understanding of the relationships among the technical issues. In a series of workshops this year, the team is developing a mathematical model of the Yucca Mountain site based on component models of the key geotechnical issues.

Robin McGuire, an EPRI contractor who is organizing the methodology development effort, says the objective for the overall model is to quantify the proposed repository site performance under a wide range of possible effects while incorporating current earth science and engineering uncertainties. "The model will

Spent-Fuel Options for Utilities

To maximize existing in-plant storage pool capacity, most utilities have reracked pools two or three times to place fuel assemblies closer together. Also, limited demonstrations of fuel rod consolidation have been conducted, using poolside equipment to remotely pack about two 1-ton fuel assemblies into a canister the size of one assembly. But a simpler and more economical approach to storing spent fuel that cannot be accommodated in the pools—and the current choice of a number of utilities—is to use metal casks and horizontal concrete modules for on-site dry storage. Both have been demonstrated at utility sites with EPRI and government support, and NRC-licensed designs are available from vendors. Demonstration of a third design using vertical concrete casks is under way.



Horizontal concrete modules at Carolina Power & Light's Robinson plant also attempt to quantify the risk of not being able to demonstrate that Yucca Mountain meets safety criteria," he adds.

The primary nodes of the site decision model relate to the principal geotechnical and hydrologic issues: the possible interrelated effects of climate changes, earthquakes, and/or volcanoes on the water table and the effects of those changes on the near-field environment surrounding waste packages. These factors, in turn, affect the rates and form of possible release and transport of radionuclides over time into groundwater. Each branch from the nodes represents a possible alternative interpretation of a physical process based on current scientific understanding of the Yucca Mountain site. Each interpretation has an associated probability and uncertainty band.

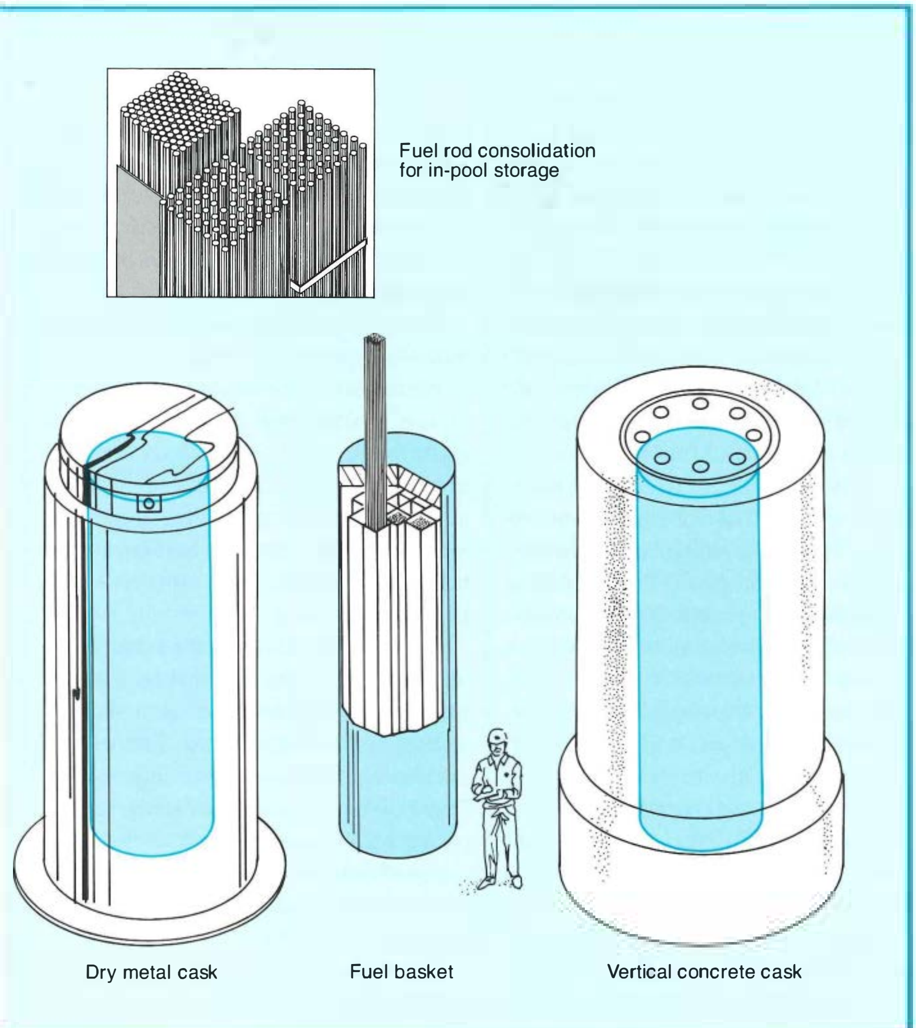
When DOE's site characterization work resumes, the basis for modeling the physical processes and the associated probabilities will be revised with better technical data. "When the model is exercised through the various possible chains of events and probabilities, one of the objectives is to classify the uncertainty and identify the particularly sensitive parts of each link so that the exploratory work at the site can focus on reducing uncertainty in our understanding of the more important physical processes and helping to identify more closely the sensitive variables," says EPRI's Shaw.

According to Stepp, who heads EPRI's nuclear seismic risk program, "The complexity and number of variables involved in assessing a repository site are much greater than for looking just at the seismic hazard at the site of a particular nuclear plant. At Yucca Mountain, the requirement to quantitatively demonstrate high confidence of radionuclide containment for 10,000 years is a rather severe demand methodologically, but it is not necessarily more uncertain or difficult to evaluate because of the time variance of geological phenomena over 10,000 years, which in a geologic context is a relatively short time.

"We can say with a high degree of confidence that in 10,000 years geologic conditions around the site will be about the same as they are now. Time variation appears to be a key issue in the climate model, however," Stepp explains. "We know that climate can vary over intervals of 10,000 to 100,000 years, including changing from an interglacial to a glacial period. So predicting the rate of time variance in climate change over the period of concern for a high-level waste repository is a bit more demanding than the other aspects."

Stepp says atmospheric loading of carbon dioxide, presumed in studies of the greenhouse effect to play a major role in near-term climate changes, is "just another complication" to consider in the climate model for the HLW repository. There, the focus on climate is longer-term and more on the multimillennial glacial cycles that are driven by astronomical forces rather than human forces. "The complication is that human activities could slow the glaciation cycle," he adds.

At the end of the methodology development effort's first phase later this year, EPRI and industry representatives will present the methodology in detail to DOE, which has up to now informally monitored the work through observers at meetings and workshops. Beyond that,



says Shaw, "we will need DOE participation, cooperation, and funding" to implement the model as part of the site characterization process.

But while Shaw acknowledges that EPRI's effort does not address the immediate political and legal issues holding up site characterization, Stepp notes that the Institute's methodology project is really aimed at "cutting through to the technical issues that are at the heart of the dispute. All of the political disputes basically give lip service to the technical question, is the site safe?" Stepp goes on, "The image created in all the political back and forth is that determining the suitability of Yucca Mountain is an unresolvable problem. We intend to demonstrate that it is not an unresolvable technical problem. It *can* be determined whether the site is suitable for an HLW repository. It's neither an impossible task nor one that should take 20 more years."

Utility options for spent-fuel storage

Given the delays in determining Yucca Mountain's suitability as a permanent HLW repository, Shaw says an aboveground monitored retrievable storage (MRS) facility, which could be readied within a few years of identifying a suitable site, may be essential if DOE is to begin taking receipt of reactor fuel in 1998, as specified in the waste law.

The MRS concept was proposed several years ago for the former site of the canceled Clinch River breeder reactor near Oak Ridge National Laboratory in Tennessee. But fears that an MRS could end up a de facto HLW repository if a permanent site was not opened led Tennessee authorities to oppose the project.

The 1987 waste act amendments tied congressional approval of an MRS with the identification of a suitable site for a permanent repository and progress toward opening it. Despite acknowledging the emerging need for an interim central storage facility, a congressional commission in 1989 did not strongly endorse building one as long as it is linked with the repository.

In the same report to Congress last November in which he disclosed the slip in the schedule for opening a permanent repository, Energy Secretary James Watkins indicated that DOE could still fulfill its commitments to begin accepting spent fuel from utilities in 1998 if Congress would again amend the waste act and decouple an MRS from the HLW repository. Plans also call for a presidentially appointed federal waste negotiator to seek a state willing to host an MRS facility.

Meanwhile, utilities continue to bear responsibility for safely storing spent fuel at the reactors, under NRC regulation. According to Ray Lambert, a technical specialist in the EPRI high-level waste program, utilities first began looking at the 1998 fuel turnover date with apprehension six or seven years ago. "Prudent planning suggested having an interim means of storing spent fuel in case a repository did not open in time," he says.

"Such planning led to strategies that combine reracking of existing plant fuel pools to hold more assemblies with the later use of dry casks and concrete modules to hold excess fuel from the storage pools," adds Lambert. "It was earlier thought such strategies would also include widespread use of fuel rod consolidation, but demonstration experience has somewhat dampened the immediate interest in that approach. Rod consolidation remains attractive to several utilities, but it needs further R&D."

Reracking involves replacing the existing spent-fuel storage racks in the pools with redesigned structures that space the fuel assemblies closer together. Neutron-absorbing materials are used to prevent criticality. Many utilities have reracked their fuel pools two or three times.

As part of its commitments under the waste act, DOE has shared with utilities and EPRI the cost of demonstrating the use of the hardware and the regulatory licensing of fuel rod consolidation, as well as a variety of dry metal storage casks, concrete storage casks, and horizontal concrete storage modules. Several of these designs are now licensed by the NRC and available from vendors.

Rod consolidation involves remotely taking apart submerged fuel assemblies and packing some two assemblies' worth of individual fuel rods into a canister the size of one assembly. The end-fittings and other scrap components are compacted and stored in another waste canister that remains in the pool along with the consolidated fuel.

According to Lambert, "While the economics of rod consolidation still appear favorable, the processes that have been employed are time- and labor-intensive and have a significant impact on plant operations. The efficiency achieved to date in compacting the residual bundle scrap has also been less than desired. Further R&D is planned to address these shortcomings by working with utilities and vendors to develop and demonstrate improved, more automated rod consolidation systems."

Meanwhile, thanks to the cooperative utility–EPRI–DOE demonstration programs of the last several years, a competitive market in alternative dry storage designs exists today. "EPRI got involved in trying to help drive the cost down and in trying to foster an environment that would make available a range of cost-effective, licensable interim dry storage systems," Lambert explains.

Large, vertical, thick-walled ductile-iron and steel containers that hold 20 or more fuel assemblies were the first dry storage casks demonstrated. Today there are four licensed vendors of such casks. These casks are submerged in the fuel pool for loading, then dried, capped, removed, and trundled to a concrete pad area next to the plant for long-term storage.

To reduce the cost of dry cask storage, a new design has been developed that replaces the thick metal shielding with 3 feet of concrete. In one concrete system design (NUHOMS), dry sealed canisters of fuel loaded in the pool are moved to and emplaced in horizontal, natural-circulation air-cooled modular concrete vaults via a shielded transporter. "Although the hardware itself is cheaper, the method does entail somewhat greater operational impact than a no-frills, fill-a-cask approach," notes Lambert.

Still, "concrete storage modules are a leading contender among the dry storage options," says Lambert, in part as a result of NRC licensing of NUHOMS technology on the basis of its demonstration (in which EPRI played a substantial role) at a Carolina Power & Light plant. In addition to CP&L, Duke Power and Baltimore Gas & Electric have committed to use this technology.

Lambert says the demonstration success and attractive economics of horizontal concrete modules have spurred metal-cask vendors to new, lower-cost designs. Meanwhile, EPRI is participating in a demonstration of a vertical, ventilated concrete cask with Wisconsin Electric Power that may have even lower costs than the horizontal modules.

Assuming responsibility

In an era when recognition of the social responsibility to future generations in matters of environmental protection runs deep, it is important to fulfill the national commitment made decades ago to rationally and responsibly deal with the waste by-products of society's use of nuclear energy. With nuclear power now providing a fifth of the nation's electricity and the possibility that it may play an even greater role in a future of limits on fossil fuel combustion, collectively accepting responsibility for dealing with nuclear waste as a society is as important as ever.

But successfully implementing a long-term radioactive waste disposal program requires a process compatible with democratic governance that can achieve and maintain public acceptance of the premise that high-level waste can be disposed of with acceptably low residual risks and uncertainties. "This is a difficult and complicated objective, involving both public perceptions of risk and expert technical knowledge," notes Chris Whipple, technical manager of environmental risk analysis in EPRI's Environment Division.

"I believe the problem requires a more flexible and responsive national approach than has been pursued up to now," says Whipple, a member of the National Academy of Sciences Board on Radioactive Waste Management, which reviews and advises the government waste management program. "An essential part of a successful plan is to figure out how to operate with large residual uncertainties in the long timeframe specified. An approach that anticipates that science can provide all the answers is likely to fail."

In a conference paper presented earlier this year, Whipple recommended an iterative approach to repository site performance assessment. Rather than focusing on the uncertainties that could stand in the way of repository licensing, the federal program should instead be receptive and adaptable to the continuing stream of information from site characterization and continuously redefine the important issues in assessing suitability. "Public confidence in DOE and its contractors is central to acceptance of a repository. A flexible approach, based on the expectation of unanticipated events during characterization and construction, has the best chance of succeeding," said Whipple.

The question of what is an acceptable level of residual uncertainty in risk from a waste repository deserves further examination, added Whipple, suggesting it also should be asked in reconsideration of licensing criteria. "While reducing uncertainty through investigations of site characterization is certainly desirable, the track record in risk analysis is that uncertainties in risks from activities for which there is no actuarial basis for assessment fall slowly, if at all."

EPRI has taken the initial steps in assuming an expanded role on behalf of the electric utility industry aimed at helping refocus efforts toward early determination of the suitability of a proposed site for a permanent high-level nuclear waste repository. For the time being, those efforts are a reflection of the state of the national commitment to manage nuclear waste.

But there should be no illusions about the prospects for dramatic results from the utility industry's effort to catalyze a fresh approach to assessing Yucca Mountain as a permanent repository. With its many dimensions—political, regulatory, technical—and the sometimes conflicting roles among institutional players, the high-level nuclear waste arena will likely remain contentious and subject to program delays and state opposition, as well as to the changing winds of politics, legislation, and regulation. ■

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This article was written by Taylor Moore. Background information was provided by Ray Lambert, Robert Shaw, J. Carl Stepp, and Robert Williams, Nuclear Power Division, and Chris Whipple, Environment Division.

"Ever since the power outage last night, the digital clock on my VCR has been blinking. Does this mean I have to reprogram it to record my soap operas tomorrow? Can you tell me how to do it?"

THOSE *#@%!! BLINKING CLOCKS

"I have eleven digital clocks in my house, and now they're all blinking at me. Can you send somebody over right away to reset them?"

"My client is a professional basketball player. This morning he woke up with his digital alarm clock blinking and missed the team plane—and now he's facing a stiff fine. We would like a statement from you people to the effect that this is your fault and not his."

Electric utilities from rural Georgia to metropolitan San Francisco are receiving questions and complaints from residential customers about trouble with digital clocks. Interruptions in the power supply, even those lasting fractions of a second, will often upset or "crash" the electronic displays in these clocks, causing them to literally go on the blink. Utility customers, often without any understanding of the problem or of how they might avoid it, find themselves faced with the irksome task of resetting their bedroom alarm clocks, along with the digital clock displays on their microwave ovens, dishwashers, and VCRs, each of which may require a different resetting procedure. As a further aggravation, these appliances may have been programmed to cook, clean, or record while the customer was away during the day, and he or she may arrive home to find the dishes dirty, dinner uncooked, and a favorite TV program untaped. Naturally, customers turn their questions—and sometimes their anger—in the direction of the provider of electric service: the electric utility.

Although the blinking-clock problem may seem like little more than a minor nuisance, it represents an increasing source of friction between utilities and their customers. Most important, clocks that require resetting as a result of unavoidable interruptions of very short duration—performed to prevent longer outages of major consequence—can lead customers to believe that they are being inconvenienced by utility negligence, or that the utility is not delivering its usual, highly reliable service. These perceptions, which are almost always based on a misunderstanding of the problem, can harm the utility's relationship with the customer and undermine its standing in its service territory. EPRI and its member utilities are thus taking the problem seriously.

In response to direct requests from utilities to do something about blinking digital clocks, the interdivisional power qual-

THE STORY IN BRIEF

It's a problem all too familiar to anyone with a digital clock: the clock's display suddenly loses track of time and blinks until it is manually reset. Many residential customers see this as an annoying signal that their electric utility is no longer providing reliable service. However, laboratory tests at EPRI's Power Quality Test Facility show clearly that the change has been not in service quality but in the devices themselves. Clocks manufactured in the 1970s included capacitors that would allow them to ride through normal split-second utility switching operations and other momentary interruptions. In later models, manufacturers substituted smaller capacitors, which leave the clocks more vulnerable. Findings from the EPRI tests can help utilities inform their customers about options to protect clocks from "display crashes," and the Institute plans to work with clock manufacturers and standards-setting organizations on features that will make clocks less susceptible to interruptions.

ity team at EPRI has been working on the problem since mid-1989. "We're on a blinking-clock crusade," says the Institute's William M. Smith, manager of the Power Electronics and Controls Program. "We're working to understand the problem, develop solutions, and relay helpful information on digital clocks to utilities, their customers, and equipment manufacturers."

Dealing with a digital world

Blinking clocks are but one manifestation of the challenges imposed on utilities by the microelectronics revolution. Computers and other equipment using solid-state electronics are highly sensitive to the quality of the electricity supplied to them, much more so than the electric motors and incandescent lights that were the primary users of power in the first half of this century.

The Institute is addressing a range of problems related to power quality and its effects on electronic equipment through coordination of the staff resources in EPRI's Customer Systems and Electrical Systems divisions and through the establishment of the Power Quality Test Facility (PQTF) at the EPRI Power Electronics Applications Center (PEAC) in Knoxville, Tennessee. Up until now, much of EPRI's power quality work has responded to problems of commercial and industrial customers, such as the sensitivity of computers and electric-powered industrial processes to disturbances in the power supply. Now, with digital clocks emerging as an important customer and utility concern, EPRI's power quality research is focusing on the residential sector as well.

To address the digital clock problem, EPRI researchers are employing an approach similar to the one they've used successfully in the commercial and industrial sectors: understand the causes of the problem, determine alternative solutions and their relative costs and value, and ensure that the relevant parties receive the information.

In the case of digital clocks, the laboratory staff at the PQTF began by evaluating a broad sampling of clocks and identified the kinds of disturbance in the power supply that cause their displays to crash. Having clarified the issues involved and identified alternative solutions, the PQTF staff is now working to pass this information on to utilities and their customers. In addition, EPRI will provide the information to the new IEEE Power Quality Standards Coordinating Committee for use in communicating utility and customer concerns to the manufacturers of appliances containing digital clocks and timers.

"For digital clocks, as with other power quality issues, we aim to coordinate the efforts of the customer, the utility, and the equipment manufacturer," says Smith. "Once these three groups share a common understanding of the problem, including a common set of terms, definitions, and standards, a workable solution should emerge."

Why clocks blink

One of the key findings of the PQTF laboratory evaluation is that momentary power interruptions, more than any other disturbance, cause digital clocks to blink. In the course of the evaluation, researchers tested the sensitivity of a representative sample of clock designs to many different kinds of power disturbance that can occur in residential environments. "We subjected the clocks to everything they might be expected to encounter in the field," says PQTF manager Tom Key. Phenomena such as surges and sags in voltage, long-term undervoltage, and harmonic interference from the operation of other kinds of equipment nearby are generally not the culprits.

Instead, the evidence indicates, most troubles with blinking digital clocks are caused by very brief power interruptions—usually lasting less than 30 seconds and often less than a second—that result from utilities' automatic switching operations performed to avoid serious long-term outages from natural events such as lightning strikes, falling tree limbs, and high winds, or from human activities involving kites or metallic balloons.

EPRI's Greg Rauch, a project manager in the Electrical Systems Division's Distribution Program, offers an example. "When lightning strikes on or near a power line, it can cause an insulator flashover, a type of short circuit. This is detected instantly by relays, which automatically open circuit breakers to eliminate the flashover, then reclose the breakers to restore the line to service. The whole process may take less than a second—you may not even notice your lights flicker—but that may be long enough to crash the displays of some digital clocks."

From the utility standpoint, such momentary interruptions indicate that the distribution system is operating as it should—that it is working automatically to prevent outages of long duration. "But most customers are not familiar with the principles of electric power distribution," says Marek Samotyj, a project manager in the Customer Systems Division. "These momentary interruptions generally have no major adverse consequences on any equipment or operations, except they upset clock displays. And when customers see their clocks blinking, they conclude that they are having problems with power quality. It's a frustrating problem because it's an issue of wrong conclusions drawn from perception rather than fact."

The frustration is echoed by utility personnel who respond to questions and complaints. "Customers who call us to complain about interruptions that caused their clocks to blink generally aren't satisfied with a technical explanation of why that interruption occurred," says Bill Moncrief, manager for enhanced power quality at Georgia Power. The problem is taken seriously by his utility, he says, because of the competitive situation in Georgia. "There are 96 electricity suppliers in the state, so we're motivated to provide a high level of service. We have a strong system that performs its protection functions properly—but clocks still blink."

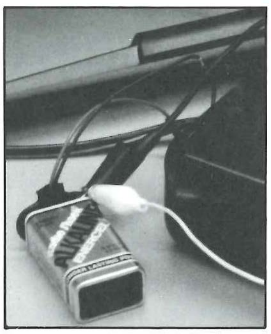
Moncrief offers an interesting perspective on the issue. "Digital clocks are very sensitive instruments for monitoring electrical power continuity," he says. "They weren't intended to be, but they are. The clock can look back through its plug deep into the distribution system and react to events that may occur miles away and have no other consequence for the customer. Utilities do a remarkable job, creating 5,184,000 cycles of electricity every 24 hours; the monitoring capability of digital clocks—which are working 24 hours a day all week long—holds the utilities to a standard that far exceeds that found in any other industry."

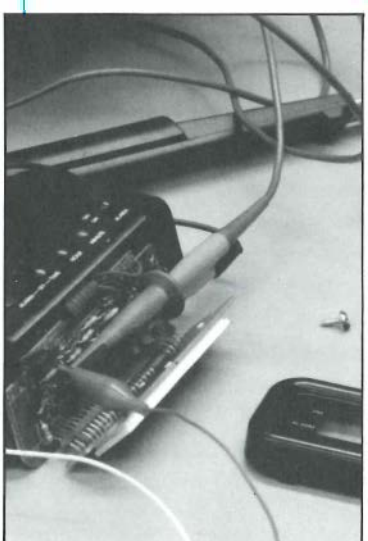
Backup power

The crucial question in clock design, as the PQTF evaluation shows, is whether the clock has some sort of backup power supply, or ridethrough feature, to power its timekeeping circuit in the event of an interruption. The PQTF staff made an interesting discovery on this point. Older clocks, manufactured in the 1970s, generally had capacitors—temporary energy storage devices—that were larger than those used in clocks of more recent manufacture. These larger capacitors provided a ridethrough time of 2–10 seconds, enough to tolerate most momen-

Testing Clocks in the Laboratory

To determine what causes digital clocks to blink, researchers at the PEAC Power Quality Test Facility subjected a representative sampling of clocks to a spectrum of power quality disturbances. The evaluation revealed that momentary power interruptions, more than any other type of disturbance, caused the blinking. The test data can help in rating clocks according to their susceptibility to momentary interruptions and in developing alternative technical approaches for making clocks less vulnerable to these interruptions.





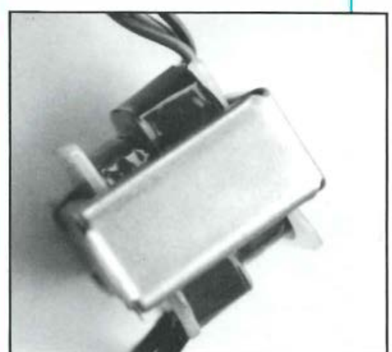
KEY FINDINGS ON DIGITAL CLOCKS

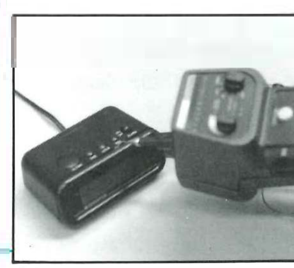
Older clocks

- Generally had capacitor ridethrough (2–10 seconds)
- Generally did not have battery compartments

Newer clocks

- Upset by momentary loss of voltage (such as during recloser operation)
- 95% have backup-battery compartments
- Batteries not included
- Will run slightly fast as a function of temperature during backup mode if battery voltage is less than 8 V
- Will run slow during backup mode if battery voltage is greater than 8 V
- Are generally immune to surges up to 6 kV
- Memory and timekeeping function draws only 4 mA, but the numerical display draws approximately 400 mA





Alternative Paths to a Nonblinking Clock

EPRI is exploring several technical alternatives for making blink-free clocks. At present, battery backup is the only option that is widely available, but this approach falls short of being a perfect solution. The Institute plans to work with clock manufacturers and standards-setting organizations to define, develop, and implement no-blink features.

Backup battery Most digital clocks now have a compartment for a 9-V battery to power the clock during interruptions. The battery is not included in the clock purchase, however, so the customer must remember to buy and install one. Moreover, these batteries lose their charge over time and require replacement. In addition, clocks powered by backup batteries don't keep time as accurately as those supplied with ac power.

Rechargeable battery Perhaps the best solution from the performance standpoint, an automatically rechargeable nickel-cadmium cell would eliminate the problem of battery drain. From the standpoint of customers and clock manufacturers, however, this option may mean additional cost.

Low-voltage indicator In a clock equipped with a backup battery, a low-voltage indicator would alert the customer when the battery needs replacing.

Reset button Since a clock's memory draws about 100 times less energy than the numerical display, the memory may live on even if the display went unsupported during an interruption. It may be possible to add a circuit and an automatic reset button that, when pushed, would ask the memory to tell the display the correct time.

Larger capacitor A sizable capacitor providing additional ridethrough time would protect a clock display from the majority of interruptions. A ridethrough time of 30 seconds or so should protect against interruptions due to utility switching operations.

tary interruptions. Newer clocks, however, perhaps to shave production costs, generally have much smaller capacitors that provide only a split second's worth of ridethrough.

This fact may explain customers' perception that their electrical service is deteriorating, suggests Samotyj. "Perhaps their older clocks didn't blink as often because of the longer ridethrough time provided by the larger capacitors. The change is not in their electric service, it's in the clock."

The good news for utilities and their customers, the PQTF found, is that nearly all the digital clocks manufactured since the mid-1980s have a battery ridethrough capability to keep them going during outages. The least expensive and by far the most common system is a standard 9-V battery the size of a matchbox, which the customer must buy separately and install in the clock. The backup battery may be an adequate solution, but it's not a perfect one. Tests show that such batteries often do not keep time as precisely as ac power, though their inaccuracy doesn't present much of a problem during momentary interruptions. The main problem, of course, is that the battery is not included with the purchase of the clock and is not necessary to the clock's ordinary operation; therefore, many customers neglect to buy a battery in the first place. In addition, if the backup battery is called into service it will lose its charge over time and require replacement, but the customer may not be aware that the battery is low.

Perhaps the best solution, from the utility standpoint, would be a rechargeable nickel-cadmium cell of the kind built into some of the VCRs on the market today. Such a cell would be charged automatically during normal operation, eliminating the problem of battery drain, and might fit into the battery compartment of existing clocks. From the point of view of the customer and the manufacturer, of course, this rechargeable battery means extra costs. Utilities might play an active role in promoting ridethrough-enhanced clocks by offering a rebate to a customer who buys one or by sponsoring programs in which the customer exchanges an old clock for a discount on a new one with a rechargeable battery. Or, the manufacturer might provide add-on devices, such as rechargeable battery–recharge circuit combinations, approved for retrofit in equipment like VCRs and microwave ovens to protect the memory, the schedule, and, of course, the clock.

The results of the PQTF testing, along with alternative approaches for dealing with the issue, will be described in an upcoming PEAC report that will help utilities inform the customer about the options available to protect clocks from outages. To provide such information to customers before they become irate over blinking clocks, utilities can communicate through inserts in monthly bills, or in special communications such as newsletters and brochures. "In all power quality issues, the customer has to understand what to expect from both the equipment and the utility," says Smith. "If expectations are realistic, the relationship is more likely to be a good one."

One realistic expectation is that power interruptions are an unavoidable fact of life, according to Greg Rauch. "Utilities will always have to contend with elements of nature, as well as impacts from human activity."

Edgar Holt, manager of new products and services at Florida Power Corp., says that his utility's campaign to inform customers about the availability of clocks with battery backup has met with some success. "Because of the amount of lightning we get here, it's not unusual to have a split-second interruption several times a day, and for a while blinking digital clocks were our number one complaint." The number of complaints has been declining, he says, with growing customer awareness.

Reaching the manufacturers

Beyond educating the customer, utilities have another goal. They would like to see digital clock manufacturers make their products immune to momentary interruptions and more compatible with the power system. Technically, the problem should be fairly easy to solve, says Samotyj, referring to several conceptual alternatives that were developed as a result of the PQTF testing program.

For clocks equipped with a battery compartment, a low-voltage indicator would eliminate one of the drawbacks of battery backup—the customer's inability to tell when the battery has expired. Another approach is an automatic reset button, a solution that was suggested by one of the findings at the PQTF. "We learned that the numerical display in a digital clock consumes about 100 times more power than the memory," he says. "So while the display will die almost the instant that power is interrupted, the memory will live on for a while. It may be possible to install a button that, when pushed, would ask the memory to tell the display the right time and then reset the clock automatically." Another possible solution would be to redesign the integrated circuit in the clocks to operate normally on a low-power dc crystal like those used in wristwatches, and provide a lifetime lithium battery for backup.

But getting clock manufacturers to implement such solutions is a different story, according to Samotyj. "All the digital clocks sold in this country are imported from Asia, and establishing a dialogue with the overseas manufacturers has been all but impossible," he says.

These clock manufacturers operate in a highly competitive market with narrow profit margins and are reluctant to add features that add to their costs. "The real problem," says Samotyj, "is that without a well-defined standard that requires the manufacturers to include ridethrough capability, they will not add these features because of the cost impact." To help lower the cost to manufacturers of implementing such features, Samotyj says, EPRI may sponsor the development of generic digital clock circuit designs that will accommodate a rechargeable battery, a low-battery indicator, or an automatic reset button. "We would then make these designs available to the manufacturers," he says.

Working toward the goal of increasing the immunity of digital clocks, EPRI plans to influence the design of future clocks through participation in standard-setting groups. William Smith is currently serving on the newly formed IEEE Power Quality Standards Coordinating Committee, an ideal setting for the development of standards related to digital clock displays and ridethrough capabilities.

"There's no doubt that EPRI and the utilities have a major, positive role to play in ensuring the future compatibility of digital clocks with the power grid," says Smith. "We have to work with the manufacturers to make blinking digital clocks a thing of the past."

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This article was written by Jon Cohen, science writer, and David Boutacoff, *Journal* feature writer. Background information was provided by William M. Smith and Marek Samotyj, Customer Systems Division, and Greg Rauch, Electrical Systems Division.

ENHANCING POWER SYSTEM SECURITY

Given the profound importance of electric energy to industry, commerce, and our daily lives, it is crucial that our nation's electric power infrastructure operate reliably and securely. Utilities have built reliability into the interconnected electric power system of the United States in the form of generation reserve margins, redundant and parallel subsystems, and sophisticated diagnostic equipment and techniques. Nonetheless, as a result of several factors, including growth in the transfer of bulk power and environmental and economic constraints on the construction of transmission circuits, that long-renowned reliability is being challenged. Today utility systems must withstand more stress than ever before, and some systems are pushed close to their security limits almost daily.

While reliability is a quality that is built into a power system and that characterizes the system over the long term, security may be thought of as reliability in the moment, as the ability of a system to withstand sudden disturbances under actual operating conditions at a given time. System security reflects the robustness of the power system at a specific moment, given the possibility of contingencies (events that may involve the unplanned outage of one or more power system elements) and changes in weather conditions and system load.

To maintain reliability, utilities try to operate their systems securely—from moment to moment, round the clock, day in and day out. Typically, system variables such as voltage levels and current flows define the state of the network. Control center operators, or dispatchers, must keep these variables within a safe range to ensure that the system continues to operate securely. This means that system dispatchers must either avoid contingencies or respond to them effectively when they appear.

Being forewarned is being forearmed, and the job of contingency analysis is to forewarn dispatchers about how possible

THE STORY IN BRIEF

To ensure reliable service, control center operators must constantly monitor system security—the ability of the system to withstand sudden disturbances as they appear. But it's not always obvious what will happen when the system loses a major element, such as a generator or transmission line. Will the result be a manageable surge elsewhere on the system, or a major instability problem that could cascade through the entire network? The state of the art of contingency analysis will get a major boost from demonstration of a new on-line, steady-state Security Enhancement System (SES) that offers utilities faster and more comprehensive assistance. SES not only identifies potentially harmful contingencies but also counsels dispatchers on the best options for responding to them or preventing them. In addition, research is continuing on new approaches for assessing dynamic security, which focuses on the system's response in the seconds immediately following a transient.

contingencies would affect system operations. At most utilities, planners perform contingency analyses annually or seasonally, making off-line computer studies of several hundred critical contingencies. After completing studies for various contingency scenarios under peak-load and low-load conditions, planners present the results to dispatchers in the form of rules and guidelines for avoiding or responding to contingencies.

But the system encountered by the dispatcher is always different from that studied by the planner: the synthetic world of simulated networks used by planners is unavoidably abstracted from the time-varying real-world environment familiar to dispatchers. As David Curtice, a project manager in EPRI's Power System Planning and Operations Program, says, "In operations, power systems nearly always have less than their full complement of equipment in service; thus the system that a dispatcher must deal with as his base case—the base from which he considers the potential effects of contingencies—would appear to a planner to be already operating with multiple, simultaneous contingencies. What a dispatcher should do in an actual situation can differ sharply from the planners' abstract, overly conservative recommendations."

Seeking a remedy for this situation, utilities became interested in the development of software that could perform contingency analysis on-line, using real system data. As computers and algorithms became faster, such software could be developed. But on-line contingency analysis by itself is just part of the story. While the software can indicate where a problem may occur, it has no capability to recommend actions for avoiding or mitigating the situation—this difficult task still falls to the dispatcher, who must still rely on the conservative off-line guidelines.

Thus it is no surprise that, as the results of a recently completed EPRI survey indicate, utilities want software that combines contingency analysis and security enhancement. EPRI's new Security Enhancement System (SES), developed by ESCA Corp. of Bellevue, Washington, and demonstrated at Wisconsin Electric Power's control center, is an integrated software package that does combine the two. When the contingency analysis component of SES identifies potentially harmful contingencies, SES tells dispatchers what they can do to respond to or prevent them.

Working from a set of least-cost control actions, the security enhancement component of SES recommends corrective actions for individual contingencies and also preventive actions—actions to take in anticipation of contingencies to prevent or reduce degradation of system security. By reviewing and acting on the SES recommendations, dispatchers can alleviate equipment overloading, control abnormal voltages, and make cost-saving adjustments while maintaining power system security.

Security enhancement software

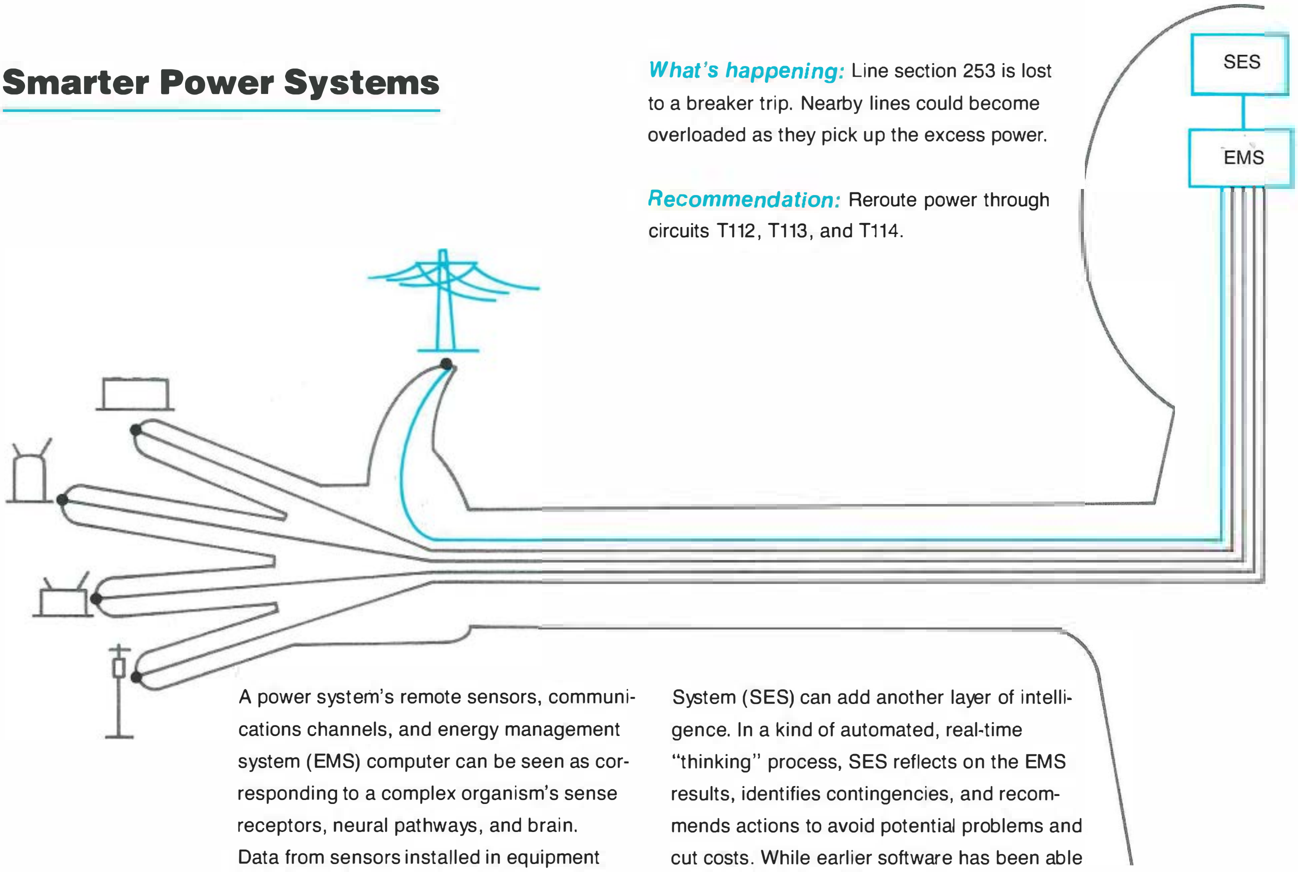
Intended for use in on-line computer systems, SES is designed to use real-time data obtained from a utility's energy management system (EMS). In addition to processing tremendous volumes of data telemetered from sensors installed in equipment throughout a utility's service area, an EMS runs a type of software known as a state estimator. A state estimator reliably estimates the current network state, including the voltage and angle at every bus, the amount of real and reactive power flowing through every branch, and the connectivity of the network. Periodically—typically every 1 to 10 minutes, depending on the size of the network and the speed of the computer—the state estimator provides an updated solution that serves to define overall system conditions.

In an important sense, by rapidly processing such real-time system data, SES transforms contingency analysis and security enhancement from abstract planning activities into control-center-based, real-time planning. Every time a state estimator completes a cycle, the software applies utility-specified models to look for things that could go wrong and for ways to operate more cost-effectively. If it finds any threats to security, SES recommends situation-specific actions that conform to utility-specific needs and operating policies. Assuming a 5-minute state-estimator cycle, the network-state solutions for two successive cycles are usually quite close together—in the same narrow bandwidth—and contingency plans and preventive actions based on the first solution generally remain valid for the subsequent period. SES and the state estimator can be synchronized. When this is done, the model executes in real time in the sense that it takes the network-state solution as input and provides recommendations in time for system operators to take effective action at the start of the next state-estimator cycle.

By enabling utilities to bring contingency planning functions into real time, SES gives utilities the opportunity to build a new layer of intelligence into their power systems. The new character of this intelligence can be understood by means of an analogy in which power systems are likened to complex organisms. Remote sensors, communication channels, and EMS computers may be regarded as electronic counterparts of the sense receptors, neural pathways, and brain of an organism's nervous system. The state estimator can then be seen as processing sensory information and reducing it to a useful, perceptual order.

Thus, with SES a power system may essentially "think" about its situation as it operates—the network-state solution, which summarizes sensory input, marks the beginning of each moment of experience. Within that moment, SES provides a sort of automated reflection on possibilities, looking out for contingencies and for ways to cut costs, somewhat as an organism seeking to survive (i.e., to stay in a safe operating region) might act to avoid harm from predators while seeking food. This automated reflection, which

Smarter Power Systems



What's happening: Line section 253 is lost to a breaker trip. Nearby lines could become overloaded as they pick up the excess power.

Recommendation: Reroute power through circuits T112, T113, and T114.

A power system's remote sensors, communications channels, and energy management system (EMS) computer can be seen as corresponding to a complex organism's sense receptors, neural pathways, and brain. Data from sensors installed in equipment throughout the system are communicated to the control center, where the EMS analyzes them to estimate the state of the network—essentially answering the question, Am I OK? At this point, the Security Enhancement System (SES) can add another layer of intelligence. In a kind of automated, real-time "thinking" process, SES reflects on the EMS results, identifies contingencies, and recommends actions to avoid potential problems and cut costs. While earlier software has been able to alert dispatchers to what might happen as a result of a system disturbance, SES is unique in that it recommends the best corrective steps for a dispatcher to take.

Signing Up for Security

A number of utilities and organizations in this country—and nearly as many abroad—have already ordered EPRI's new Security Enhancement System. Agreements to purchase SES are handled through the software developer, ESCA Corporation of Bellevue, Washington.

U.S. purchasers

Wisconsin Electric Power
Pennsylvania Power & Light
Public Service Co. of Colorado
Connecticut Valley Electric Exchange
New England Power Exchange
Puget Sound Power & Light
Electric Reliability Council of Texas
Madison Gas & Electric
Gulf States Utilities
Virginia Power

Foreign purchasers

Energy Authority of New South Wales (Australia)
Electricidade de Portugal—National Control Center
ENDESA (Spain)
Chilectra (Chile)—National Control Center
National Control Center of Turkey
Electricity Trust of South Australia
Red Eléctrica (Spain)
National Electricity Board (Malaysia)
National Control Center of Greece

occurs in parallel with ongoing power system performance, enables SES to propose actions in time for dispatchers to act before power system conditions have changed significantly. Once SES issues recommendations, the moment of experience is finished and the next one begins.

To build this new type of intelligence into the system, each utility must supply three kinds of models, developed off-line, as input to the software. These models—the network, security, and optimization models—frame the "thinking" performed by SES.

The network model physically defines the specific power system the dispatcher is working with; it represents such equipment as generators, circuit breakers, and transmission lines. Because today's power networks are highly interconnected, the network model commonly extends far beyond the utility's ownership border.

The security model incorporates all constraints that represent important security concerns for the utility—for example, limits on line, transformer, and branch group flows; bus voltage magnitude; angle pair separation; and amount of spinning reserve. Utilities can specify more than one limit on some of the factors of concern, including line flow, and thus can model problems with different degrees of severity. Because limits may often be exceeded safely for sustained periods, users of SES can define time periods for thermal limits on lines and transformers.

In addition to modeling constraints and controls, the security model also covers the contingencies of concern to the utility. The list of important contingencies prepared by a utility may reflect both dispatcher experience and the results of planning studies. Each contingency to be modeled is specified separately.

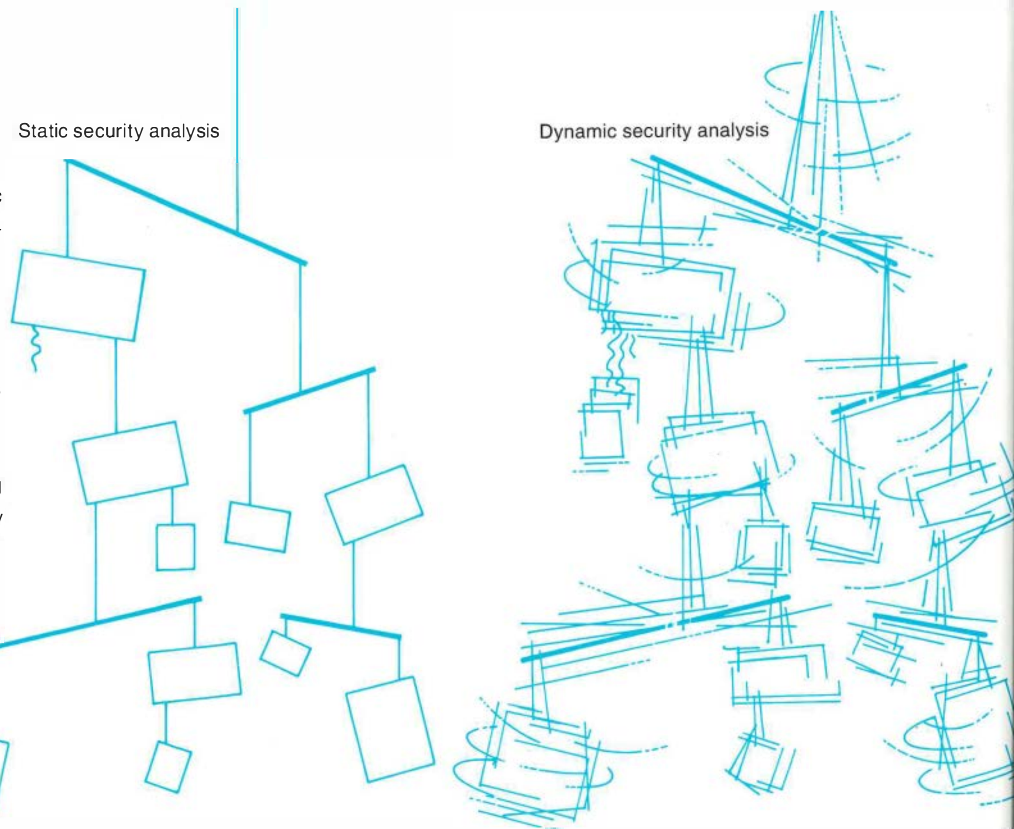
The optimization model defines the utility's preferred approaches for reducing costs and alleviating security problems that may arise when the system is operating outside preset thermal or voltage constraints. It essentially tailors SES's recommendation basis to match the utility's operating policies. Principal optimization model components include mathematical functions that yield cost curves for megawatt production, for reluctance to moving equipment away from current settings or toward operating limits, and for moving equipment toward desired, utility-specified settings.

The optimization model also includes priority orders for constraints and controls and specifies rules for network switching. For example, one utility might prevent SES from recommending a reduction in the output of nuclear units and might specify that fast-start combustion turbines be used only as a last resort. Another utility might have SES recommend that combustion turbines be brought up right away if capacity must be increased.

With input from these three models, SES has the ability to make security decisions comparable to those of the best, most seasoned dispatcher. Throughout the security enhancement processes, SES

Describing the Disturbance

The difference between static and dynamic security analysis can be illustrated by comparing the disturbed power system to a mobile that has lost one of its parts. Static (steady-state) security analysis tells the dispatcher what the system's postdisturbance steady state will be; that is, it predicts how the mobile will look upon coming to rest again, although it cannot describe all the bounces and turns involved in reaching this static, lopsided state. Dynamic security analysis, in contrast, describes how the power system behaves during the transition from one steady state to another.



attacks problems in a sequence that emulates the procedure followed by a dispatcher in relieving overloads, but SES proceeds faster and with greater overall economy (see sidebar). This emulation gives further point to the notion that SES can build a new type of intelligence into power systems.

Dynamic security assessment

Still, in some situations a power system may not perform as SES predicts. Why not? Principally, because SES performs a steady-state analysis of the power system. Steady-state security analysis assumes that the transition from one network state to another will take place smoothly, proceeding from one stable operating condition to another stable condition. However, this is not always the case. Because SES cannot analyze the transition between steady states, it might fail, for instance, to reveal dangerous transient overloads or a loss of generator synchronism.

"With dynamic security assessment [DSA], the transition itself is of interest," explains Neal Balu, manager of EPRI's Power System Planning and Operations Program. "DSA complements steady-state security analysis and checks on whether the transition would lead to a stable operating condition. Obviously, DSA does not merely constitute an academic refinement of the steady-state approach. The closer power systems operate to their limits, the more important it becomes to be able to analyze system dynamics rapidly."

Transmission lines bring large quantities of bulk power from generating plants to population and industrial load centers—hundreds of miles in some cases. Increasingly, however, these same lines are being used for other purposes as well: to permit the sharing of surplus generating capacity between adjacent utility systems, to ship large blocks of power from low-energy-cost areas to high-energy-cost areas, and to provide emergency reserves in the event of weather-related outages. Economic energy transactions, reliance on external sources of capacity, and competition for transmission resources have all led to higher loading of transmission systems and heavier loading of tie lines, which were originally built to improve reliability and were not intended for normal use at heavy loading levels. As a result, systems are now operated much closer to security limits than ever before.

These trends have adversely affected system dynamic performance. In this context, dispatchers often encounter situations where dynamic constraints, such as stability limits, are approached before steady-state constraints, such as thermal limits. Further, a power network stressed by heavy loading responds to disturbances in a substantially different way than a nonstressed system. For example, a relatively small disturbance, which would otherwise be localized, may cause the upset of a system operating close to the stability limit. At the same time, the largest size of contingency is increasing—today contingencies involving the loss of 2000 MW or more are quite possible. Thus, to support operating functions, many more contingency scenarios must be anticipated and analyzed.

In short, the DSA problem has become a primary concern in system operations. Failure to deal effectively with dynamic security is likely to force utilities either to accept more interruptions and outages or to sacrifice economy to provide an adequate margin of safety in system operation. But dealing effectively with dynamic security issues will take some doing. Balu observes, "With SES you have time to take action; with DSA you have a different set of control options where you may have no more than 15 seconds to respond. Thus computations must be faster so that the dispatcher has information about control actions available quickly, in time to avert instability. At present, a study of a system in the 5 seconds following a transient takes about 10 minutes. To complete dynamic security analyses in a usable timeframe, traditional time-domain stability analysis must be sped up or a new mathematical approach and paradigm must be employed."

One new approach, already developed by EPRI, uses calculations based on the still-evolving concept of transient energy balance to evaluate the stability of power systems following large disturbances. Extensively tested on systems with up to 115 generators, EPRI's DIRECT software can be used to determine whether a large system will remain stable once a large disturbance is removed. Intended to complement the traditional time-domain stability programs (in performing "first-swing" stability analyses only), DIRECT provides a quantitative measure of the degree of system stability. At present, DIRECT is suitable for off-line engineering studies, but EPRI plans to demonstrate its suitability for on-line calculation of transient stability limits and for assessment of dynamic security.

Another possibility for reducing the time needed to complete traditional analyses is to process separate contingencies concurrently, using parallel processors to handle the separate analyses and calculations. Recognizing that the stakes are high, EPRI is also exploring more-novel approaches, including one that would involve training neural networks to see patterns associated with the onset of instability, and another that would use chaos theory (the mathematical study of perturbations in large nonlinear systems) to study instability in large power systems.

Once EPRI succeeds in developing on-line DSA software, it could be used in conjunction with SES, identifying those actions recommended by SES that would threaten stability and thus safeguarding the system against the inadvertent introduction of instability. Utilities could also use DSA software to take actions that would prevent the onset of unstable situations and possible cascading outages or "islanding" of portions of the network. For instance, suppose a dispatcher, reviewing real-time displays provided by the National Lightning Detection Network, sees a severe storm approaching a

Walking Through the Process

SES deals with security issues in terms of steady-state conditions based on thermal and voltage limits. The central processing that SES performs involves sequential movement through up to three phases: constrained dispatch, contingency planning, and integrated preventive action and contingency planning.

Constrained dispatch

In the constrained-dispatch phase of the SES cycle, the software focuses on the current operating state as defined by the network-state solution in conjunction with the utility's network model. Using the state solution as input, SES modifies the network model to represent changes in the real-time power state. This serves as the base case used by the contingency analysis and security enhancement components of SES.

Relying on guidelines built into the security model supplied by the utility, SES looks for security violations in the base case—that is, circumstances in which the system is operating outside preset thermal or voltage limits. If SES finds no violations in the base case, it then assists the dispatcher in reducing operating costs. On the other hand, if SES does find violations, it recommends control actions to alleviate them, once again relying on the security model, which considers all controllable equipment available to the dispatcher. Using the utility-specific optimization model, SES recommends control actions best suited to the utility's overall operating strategy. These actions may include changing generator output or voltage, committing fast-start combustion turbines, changing transformer taps, shedding load, and switching network circuits.

Contingency planning

In the contingency planning phase, SES identifies contingencies that would cause security violations if they occurred, and for each harmful contingency, it specifies postcontingency control actions that would alleviate the violation. If SES determines that a harmful contingency cannot be managed after the fact with postcontingency control action, it sets aside the contingency for handling in the third and last phase.

SES can evaluate the full range of typical contingencies, including the single outage of any network element (transmission line, transformer, generator, or load) and the opening or closing of any circuit breaker; multiple outages consisting of any combination of single outages; and "conditional" contingencies. Conditional contingencies are single or multiple outages that arise as a consequence of factors (e.g., high or low voltage) caused by one or more other outages. For example, the loss of a transmission line may cause the overloading and subsequent conditional outage of a transformer.

SES reduces the computational burden of contingency evaluation by using screening measures to eliminate consideration of those contingencies that would produce only local effects. Then, for each potentially harmful situation, SES determines how network security would be affected if the situation actually arose and recommends approaches that could be used to bring the network state back within a safe utility-specified set of limits. By focusing full computing power only on the contingencies most likely to cause security violations, SES is able to process those contingencies quickly enough for operators to be able to prevent or alleviate them.

Preventive action

Sometimes (e.g., for particularly severe hypothetical contingencies), contingency planning cannot devise a way to alleviate security violations should a specific contingency occur. Any such harmful contingencies call for precontingency analysis. During the third phase of a complete SES cycle, SES identifies the best precontingency control actions for making those contingencies manageable. To do so, SES reschedules controllers in the precontingency network (the base case) so that all contingencies become manageable, and the security and economy of the base case is preserved or improved.

In arriving at recommended control actions, SES calculates a network solution that determines the effects of controller adjustments on all constraints. For both preventive action and contingency planning, the most violated constraint is addressed first. Starting with those controllers in the most highly prioritized group, SES adjusts controllers one at a time, until the constraint is alleviated. Then SES recommends ways to alleviate the next most violated constraint and proceeds in like fashion until all constraint violations are addressed. During the third phase, preventive action planning must be integrated with contingency planning: because preventive action modifies the base case already used during contingency planning, SES updates the postcontingency recommendations in an integrated fashion that accords with the modified base case. □

portion of the power system. Using DSA software, the operator could check to see whether, under the actual system conditions, a storm-related outage and the subsequent system response could render the system unstable. If the software could perform the computations in a matter of a few minutes, the dispatcher would have time to take any appropriate preventive actions that were indicated.

The system of the future

To make the best use of DSA recommendations, utilities will have to be able to take quick action by switching fast-responding voltage and stability control equipment. Narain Hingorani, EPRI vice president, Electrical Systems Division, sees security enhancement as intimately linked with EPRI's FACTS (flexible ac transmission system) strategy. FACTS is developing power electronics that will speed up power system control and allow utilities to reliably increase power transfer by using alternative circuit paths to greatest advantage. Hingorani also sees both security enhancement and FACTS as intimately linked with EPRI's effort to develop a standardized, utility communications architecture that would eventually facilitate communication between control centers, power plants, and electronic control equipment throughout large, interconnected power systems.

"Security assessment and enhancement are vital even without FACTS, but they are complementary to and part of FACTS," says Hingorani. "FACTS gives utilities high-speed control over elements of the power system. Without corresponding security enhancement software at control centers, utilities will miss out on opportunities for economic gain opened up by the replacement of conservative, planning-based margins with realistic margins based on actual system conditions. SES and DSA go to the very heart of running a good business. Like FACTS, they enable utilities to improve use of existing facilities and overall energy efficiency."

As power interchange increases, security questions become more important, but the security considerations can then be brought to bear on the business questions. Once steady-state and dynamic security enhancement software is available, utilities will be able to factor security considerations into economic-exchange decisions. A utility could try to make its system more secure for less cost or could confidently decide whether the system is sufficiently secure to increase power sales. Further, when power is offered on a short-term basis, a prospective purchasing utility could evaluate the security aspects of the deal within a few minutes, taking into account how the utility wants to use the power. Because the real value of power is at the receiving end, the utility could then discount the value of offered power by a factor that reflects the security assessment and could make bids accordingly.

"The increase of computer power in the control center is what's making the difference, and that trend will continue," Hingorani observes. "Planning and real-time operations can be brought closer and closer together. The people who have been doing operations planning ought to come into the control center, and dispatchers should become more qualified for operating in the new on-line, computer-driven environment. And in the process, the control center can and will become much more important to business." ■

Further reading

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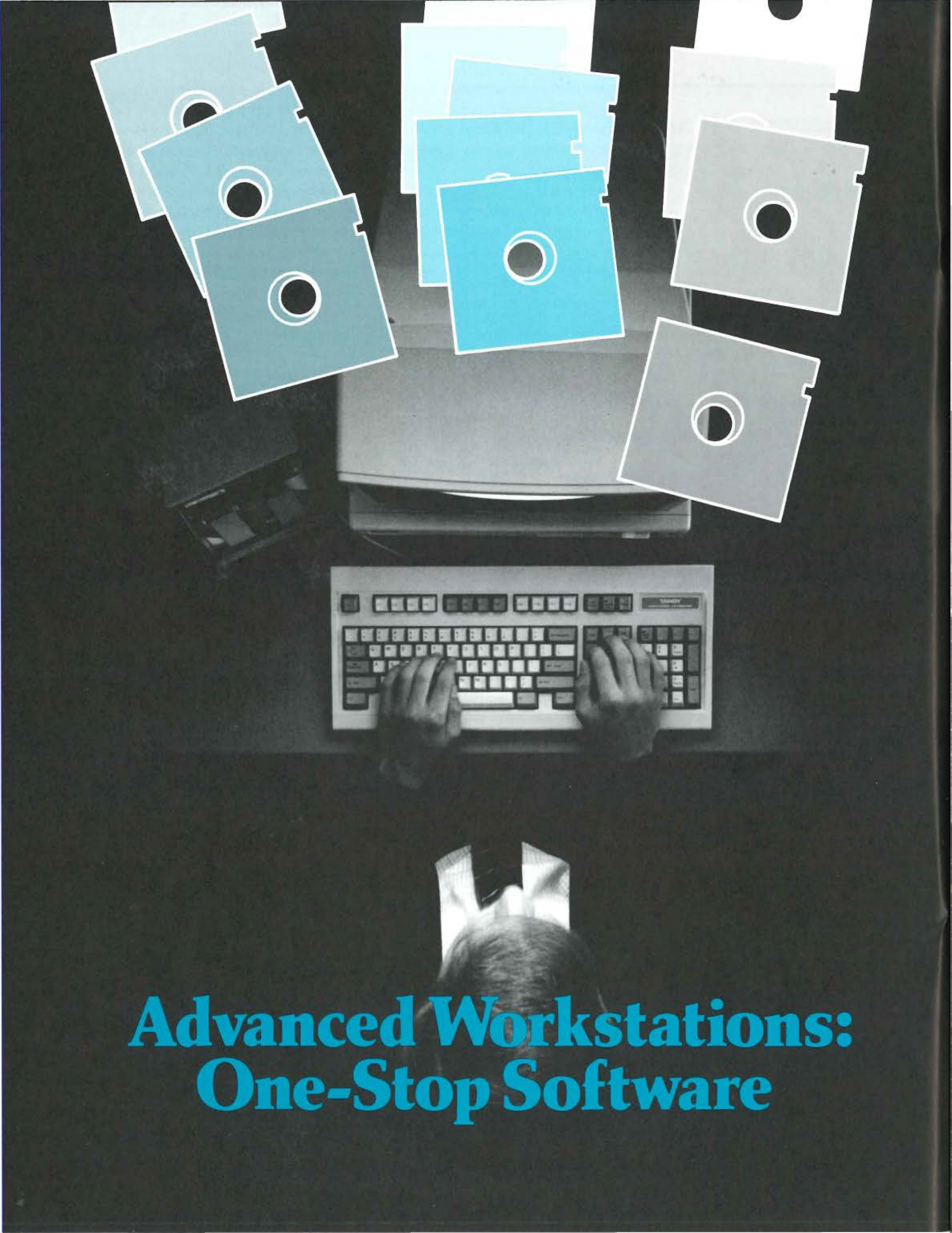
This article was written by Ralph Pred, science writer. Technical background information was provided by Neal Balu and David Curtice, Electrical Systems Division.



Advanced Workstations: One-Stop Software

Whether the project involves designing a new transmission line, troubleshooting an equipment problem at a power plant, or planning for future generating needs, utilities have used software for many years to get the job done more efficiently. Computer programs have become invaluable tools for saving time and money, and recent advances in computing power and software engineering have accelerated the development of codes for utility applications.

Over the years, these codes have been developed one by one. They use a wide variety of databases and interfaces, so users have had to develop input data for each program and learn how to run it. In addition, some of the older codes developed for utilities run on large mainframe computers, which are less user-friendly and less accessible than the personal computers now in widespread use.

In a multidivisional effort aimed at providing utilities with powerful and practical software tools, EPRI is now developing integrated packages of programs related to a common engineering function—for example, system grounding. Known as "workstations" at the Institute, these software packages allow users to perform a number of related and interdependent tasks much more efficiently than they could if the programs were used individually. Several software workstations have already been developed and are being used by utilities nationwide. Perhaps the best known of these is the TLWorkstation, developed and managed by EPRI's Overhead Transmission Program; it integrates 16 different computer programs covering virtually every aspect of transmission line design, from analyzing concrete piers to computing sag and tension in conductors. A dozen or more workstations are in various stages of development in various technical divisions.

"Our workstations have a consistent look and feel, so that learning a new program is much easier than before," says Giora Ben-Yaacov, who manages EPRI

THE STORY IN BRIEF

Computer programs help utilities with everything from designing transmission towers to developing demand-side management strategies—and each project area typically requires several different programs. But because they were developed independently, the programs often have different interfaces; the user is thus forced to spend time learning how to work with each one. To help utilities make better use of its software, EPRI is developing software packages called workstations, each of which includes several programs that relate to the same engineering function. The result is essentially one-stop shopping for software solutions. Using a standard interface and a common database, workstations reduce the time spent learning individual programs and developing data. And because they integrate programs that address various aspects of a larger problem, workstations can help utilities develop more comprehensive solutions.

workstation development. "They share input data and all operate the same way as far as the user can tell."

To develop a workstation, programmers first translate the older programs that run on mainframes into versions that run on personal computers—making the programs available to anyone with a PC. The programs' input and output structures are then modified so they can function in a common framework, and a common database for the programs is designed.

The workstations integrate existing and new software developed by EPRI and others in the industry. "The areas these workstations cover have been identified by various technical programs and their advisory task forces as key areas of engineering expertise," says Narain Hingorani, vice president for EPRI's Electrical Systems Division.

A system grounding package

One such key area is system grounding. For years, utilities have used software to analyze and design grounding systems for substations, transmission structures, and distribution equipment. But these programs have never operated under a common user interface and used a common database. EPRI's System Grounding Workstation does just that. The SGWorkstation integrates substation grounding programs and transmission grounding programs, making data preparation, data updating, and operation much easier. A utility engineer can use one of the substation grounding modules to spot unacceptable touch voltages, then switch to another module to analyze the electric current distribution among grounded structures for various fault conditions. With the information from these programs, the engineer can determine which parts of the substation ground grid must be modified to satisfy safety requirements. Then he can switch to one of the transmission grounding modules to calculate the performance of a transmission line structure grounding system. EPRI plans to incorporate more software, including distribution grounding programs, in 1991 and 1992.

Combining programs for any application

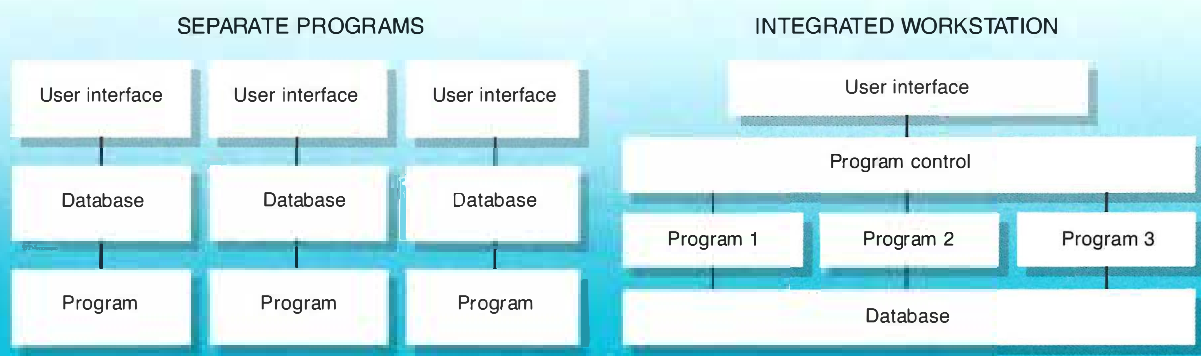
The beauty of the workstation concept is that it can be applied to any engineering function. A workstation can link programs that address different aspects of a larger area of analysis, enabling users to develop more-efficient and -comprehensive approaches to problem solving.

For example, the Integrated Resource Planning (IRP) Workstation, one of several being developed in the Power Systems Planning and Operations (PSPO) Program, will combine supply-side planning, transmission planning, demand-side planning, and risk analysis in one package. Each of these types of analysis addresses different aspects of the resource planning problem; integrating them can help utilities develop coordinated strategies for meeting future needs. This effort is coordinated with the Customer Systems Division and the Utility Planning Methods Center. "These complex computer programs were developed by various vendors in different EPRI technical divisions," says Neal Balu, manager of the PSPO program. "Integrating them will not be easy, but the potential rewards are great."

Another workstation with potentially great rewards for users is the EMTP Version 2.0 PC Workstation. Before this package was developed, EMTP—the Electromagnetic Transients Program—was a

Putting Programs in a Package

Using different computer programs usually means learning different interfaces and developing databases for each program—tasks that consume time that would be better spent solving problems. EPRI's software workstations integrate multiple programs under a single user interface and a common database, making data preparation and operation simpler and more efficient.



large, batch-oriented mainframe computer program for simulating high-speed transients in power systems. Capable of modeling momentary voltage surges lasting fractions of a second to several seconds, EMTP can be applied to switching surge analysis, synchronization problems, insulation coordination, and other important applications that make it possible for engineers to design cost-effective countermeasures.

Although it's a powerful program, the mainframe version of EMTP doesn't provide users with the benefits of PC-based software—interactive operation, menu screens, and ease of use. EPRI's EMTP Workstation puts the program into the PC framework. Input data preparation, calculations, auxiliary routines, and output processor modules are integrated by a graphic interface using the OS/2 operating system. Users can easily and consistently view and manipulate data, open multiple screen windows simultaneously, and use a mouse to change the location and size of the windows—much as they would rearrange sheets of paper on a desk.

In the area of stability analysis, several existing programs examine different phenomena separately. For example, EPRI's Small Signal Stability Program performs small signal analysis, and the Extended Transient–Midterm Stability Package performs stability analysis in the midterm range. But the phenomena examined separately in these programs are related; examining them by means of an integrated software package could suggest more-comprehensive solutions or strategies. With this need in mind, EPRI's PSPO program is developing a Stability Analysis Workstation that will enable users to select from a battery of programs that address the full range of stability analysis issues. "Pulling all these tools together should dramatically streamline stability analysis for utilities," predicts Neal Balu.

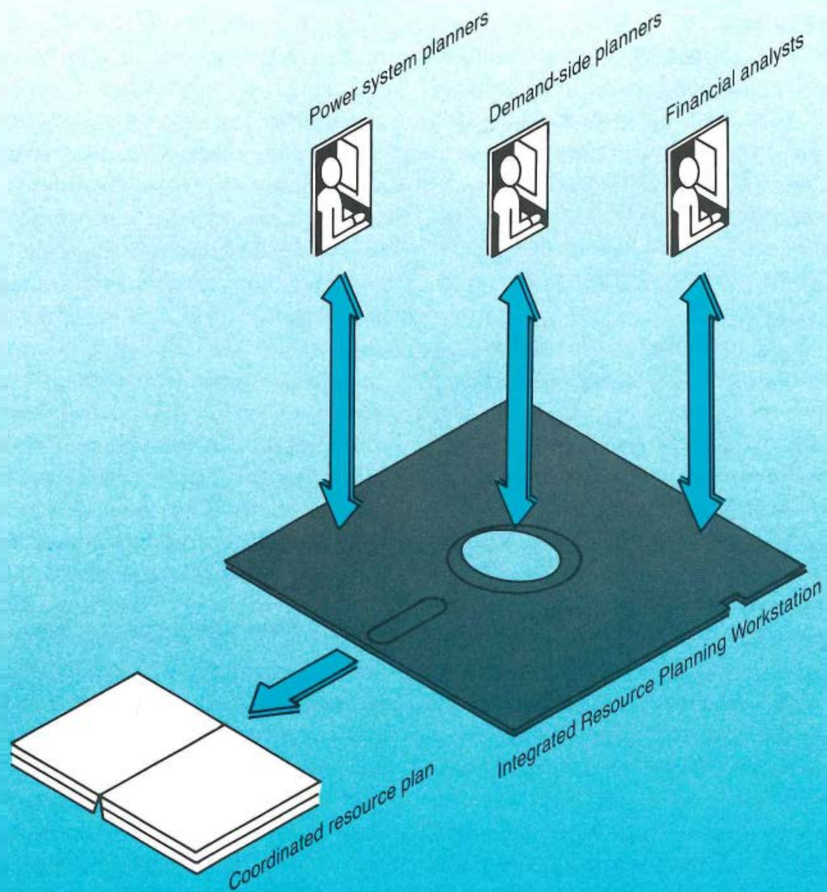
Nuclear plant workstation

One of the most comprehensive workstations available is one developed by EPRI's Nuclear Power Division. Called the Reliability Analysis Program With In-plant Data (RAPID) Workstation, its scope is the entire nuclear power plant. RAPID models a variety of on-line and off-line applications, including plant monitoring, performance evaluations, reliability analysis, and other functions. The package is the ultimate integration of software for one power plant type.

For on-line applications, a plant status monitoring (PSM) module keeps track of plant equipment status, equipment operability, and procedural compliance. Utilities can use PSM to evaluate plant health, availability, and reliability. In addition, the module produces equipment mainte-

A Coordinated Approach to Problem Solving

In some cases, different departments in a utility evaluate different aspects of a larger issue. In the area of resource planning, for example, separate groups of analysts might examine future generation options, demand-side alternatives, and financial implications. EPRI's Integrated Resource Planning (IRP) Workstation will link these functions in one software package with a common database. Thus each group will be aware of the input of the others, which promotes the development of coordinated planning strategies.

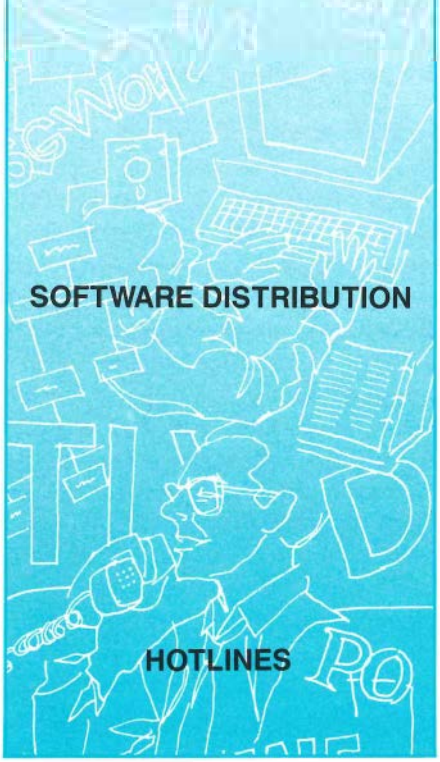


Supporting Workstation Users

EPRI workstation user support includes a wide range of activities, from organized support centers and hotlines to newsletters and users groups.

NEWSLETTERS

USERS GROUPS



nance tags, compiles equipment failure and repair histories and maintenance records, and prepares event records and shift logs. A utility module provides off-line analyses of on-line data, such as performance evaluations, analyses of operational impacts on component aging, and maintenance prioritization. Another off-line module, the reliability assessment module (RAM), helps utilities perform an array of system reliability and availability analyses. A key application of this module is performing probabilistic risk assessments or individual plant evaluations required by the Nuclear Regulatory Commission. As part of an ongoing risk management program, RAM can provide up-to-date quality assurance and quality control documentation. To make this huge package easy to use, RAPID includes a menu-driven executive interface and a sophisticated database manager.

"Prerelease testing of the software has been completed to rave reviews, and RAPID is now available," says project manager Boyer Chu. "Each of the many software modules in this workstation will substantially benefit users."

Diverse needs, different workstations

"At Arizona Public Service, we've found new ways of organizing tasks in some areas to improve productivity," says Hanna Abdallah, a senior engineer in transmission substation engineering. "We were surprised to find that several of EPRI's workstations are organized according to our way of doing things."

Recognizing that different utilities have different approaches to task organization, EPRI has tailored its workstations to meet diverse needs. For example, in response to public concern over possible human health risks from exposure to power-frequency electric and magnetic fields (EMF), software has been and is being developed to help utilities address EMF issues. At some utilities, specialists need to assess human exposure to electric and magnetic fields associated with substation, transmission, and distribution networks. Combining software developed by its Environment and Electrical Systems divisions, EPRI has begun development of an EMF workstation, which will aid in these assessments.

At some other utilities, the study of EMF issues is decentralized. Transmission designers may address EMF issues that pertain only to transmission lines. For this reason, EPRI has included relevant EMF software in its TLWorkstation as well. Using a program called ENVIRO, transmission line designers can calculate electric and magnetic fields around high-voltage transmission lines and then easily switch to 1 of 15 other TLWorkstation modules to work on transmission foundation analysis and design, structural analysis and design, or line analysis and optimization.

The TLWorkstation exemplifies a key feature of EPRI workstations—a common database. A project input module accepts input data that are common to two or more task modules. The data may be common to an entire transmission line, a line segment, or lines built with a common structure. Because each of the other task modules can access the common database, the user has to input data only once, except when updating is required. "Before we started using the TLWorkstation, we had to build several separate databases for our transmission software," relates Casimir Gudin, a transmission engineer with Centerior Service Co. "Now, by building and updating one master database, we save a lot of time."

Generating unit workstations

Several workstations are being developed to troubleshoot plant problems and improve plant performance. These functions can be performed on-line to evaluate current plant operating conditions and provide guidance on performance, equipment degradation, and maintenance needs. Off-line analyses, based on the use of archived data, provide similar results.

A collaborative effort of EPRI's Generation and Storage Division and Electrical Systems Division, the Power Plant Performance Engineering Workstation (PPP/EW) focuses on on-line analysis. The workstation interfaces with the plant computer and other instrumentation to obtain current operating data. Although the emphasis is on on-line applications, the data are archived for trending and other off-line analyses. The benefits of using these data include improving plant heat rate, enhancing maintenance planning, and increasing availability. According to project manager Dominic Maratukulam, "Determination of on-line heat rate over the load range enables more-efficient unit dispatch."

The PPP/EW's software was designed with a modular approach that facilitates long-term maintainability, standardization, self-documentation, flexibility of configuration, and consistency of calculations. This building-block design makes the system adaptable to different applications over time; moreover, it allows the workstation to interface with existing plant computer systems. For example, the PPP/EW uses the plant's data acquisition and operator control stations to display results with text and graphics that are familiar to the operating personnel.

A workstation that performs off-line analysis is the Boiler Maintenance Workstation. This workstation helps utility engineers and maintenance personnel diagnose and prevent boiler tube failures. To this end, the workstation contains modules for tracking tube failures, analyzing ultrasonic tube-wall-thickness data, determining optimum inspection intervals, and predicting the remaining lifetimes of water-wall, superheater, and reheater tubes. The package even includes an expert system for determining tube failure mechanisms and guiding root cause analysis.

The Boiler Maintenance Workstation is easy to use even for those with little or no computer experience, thanks to a user interface developed by the Institute's EPRIGEMS program. "EPRIGEMS is a product line of computer codes in which all software looks and feels the same," explains program manager David Cain. "It makes software more user-friendly and accessible to utility users." The workstation uses clear and simple pull-down and pop-up menus, fill-in-the-blank forms, graphics, and spreadsheets.

Supporting workstation users

One of EPRI's objectives is to provide utilities with software tools that improve engineering practices in the planning, design, and operation of efficient electric power systems. While this process includes program definition, R&D, utility testing, and distribution by the Electric Power Software Center (EPSC), it also emphasizes user support. "Our software research doesn't stop with testing and distribution," says EPRI's Hingorani. "We're committed to evolving interactive means to ensure that utilities get the most out of EPRI software." Centralized software services—performed by Power Computing Co.—consist of distribution through the EPSC, support, and a user hotline. In addition, there are individual workstation support centers. Each is really a network that encompasses the EPSC, R&D contractors, a users group, and EPRI staff, which together can provide a host of services—including hotlines, software maintenance, training, newsletters, and utility-specific enhancements.

Future directions

While EPRI workstations have already benefited utilities in many ways, future workstations may be even more powerful and intelligent. Incorporating artificial intelligence or expert systems technology into the interface of an existing workstation can help users solve complex problems faster and easier. In fact, an expert system has already been added to the Boiler Maintenance Workstation. Called ESCARTA, the system queries the user about the circumstances of a tube failure and provides an analysis of the failure mechanism. Once the failure mechanism is known, the system provides a list of potential root causes, along with recommendations for root cause verification, repair and inspection procedures, and guidelines for preventing future failures. This type of embedded intelligence can be applied to many other workstations.

The workstations of the future may also have more horsepower. For example, the implementation of EPRI workstations on hardware that uses the UNIX operating system could put the power of a 1980s-vintage mainframe computer on the desk tops of utility engineers in the 1990s. Such a high-powered, enhanced workstation could open up new opportunities for desktop design and analysis without sacrificing ease of use. EPRI and members of the utility community are discussing these possibilities.

The EPRI workstations already developed, as well as those envisioned, provide a novel approach to utility problem solving. Engineers need not be computer specialists to realize the full potential of computer software. The interface of the EPRI workstations frees users from complex program operation and data input tasks, enabling them to direct their attention to solving the problem at hand. Moreover, the integration of related programs that run from the same database allows users to solve specific problems or generate solutions that address comprehensive issues.

Further reading

"EMTP: Designing for Disaster." *EPRI Journal*, Vol. 14, No. 7 (October/November 1989), pp. 32–35.

"TLWorkstation: Expert Assistance in Line Design." *EPRI Journal*, Vol. 14, No. 5 (July/August 1989), pp. 32–39.

"Delivering On-Line Expertise." *EPRI Journal*, Vol. 14, No. 3 (April/May 1989), pp. 24–33.

This article was written by Steve Hoffman, consultant. Background information was provided by Giora Ben-Yaacov, Electrical Systems Division.

TECH TRANSFER NEWS

ElectriGuide Brings Databases to PC Screens

CD-ROM technology—the compact disc as a read-only memory—is proving to be an effective way for EPRI members with personal computers to search a tremendous array of research literature.

ElectriGuide is the name of the research catalog on a CD that EPRI introduced a year ago. More than 250 have been shipped to utilities. It's now in its second edition and is expected to expand into a series of topical discs, the first one likely to be on electricity end-use technologies developed by EPRI's Customer Systems Division.

Alabama Power is one of the first EPRI members to use the new resource. Herb Boyd, the utility's manager for EPRI technology transfer, has arranged for CD-ROM "players" at two PC stations, one in his office and one in the company library. Boyd is emphatic about the value of ElectriGuide. "It's timely—two editions already and quarterly database updates coming soon. And it's a good index; it's capable of keyword searches. It would be even nicer to have more full reports, especially—for us—on heat rate improvement, plant availability, and maintenance."

CD capacity is the most obvious reason for Boyd's enthusiasm. At 680 megabytes, the ElectriGuide CD is the equivalent of nearly 2000 standard floppy disks. It holds three EPRI databases, plus virtually all the Institute's short descriptive booklets and folders, 14 multimedia color-slide and audio presentations on the work of three EPRI research divisions, and several other, special information resources (some on at least a trial basis).

Given the range of information available from EPRI, the CD-ROM approach was adopted to facilitate access for PC users—especially (at first) those with IBM-compatible equipment. Economy is another consideration: CDs cut the cost of compiling, reproducing, and distributing EPRI information, and the PC user needs only to add a CD-ROM drive. More than 120 member utilities have ordered players.

Herb Boyd and his research coordinator are almost the only hands-on users of ElectriGuide at Alabama Power so far.

"Our people call us on the phone," he says, "and we search. Just the other day we were looking up information on electric vehicles to help prepare an executive speech. But we've done some training, too, and our employees use the library system.

"We're in the process of developing a dedicated PC terminal so that anyone who is on the company's office automation system can dial up ElectriGuide," Boyd adds. Alternatively, he suggests Alabama Power's plant engineers should have their own CD-ROM capability, in order to scan the index before ordering EPRI reports. "Even better, if whole reports were on the system, they could make copies of any hard data they need."

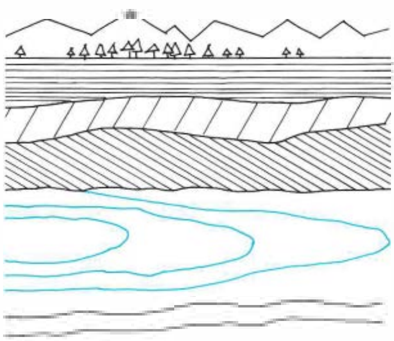
The current edition of ElectriGuide contains the Electric Power Database (EPD), with about 23,000 summaries of past and present EPRI projects, plus others from utilities and research institutes in the United States, Canada, Mexico, and Japan; the EPRI Products Database (PRODBOOK), covering about 800 R&D products developed under EPRI sponsorship; and the EPRI Publications Database (PUBS), 8000 abstracts of the Institute's technical reports, software, tapes, technical brochures and briefs, and *EPRI Journal* articles.

The same disc also pilots three down-loadable demonstrations of EPRI-developed software for end-use applications, seven full-length technical reports (and their illustrations) on commercial cool storage technology, a special database on the results of a survey of utility activities in residential and commercial demand-side management, and the abstracts of recent peer-reviewed technical articles and papers by staff members of EPRI's Environment Division. ■ *EPRI Contact: Joe Judy, (415) 855-8936*

Guide to Remediation Contractors

Waste remediation has become an attractive business venture in recent years, and the number of contractors entering the field has increased dramatically. Utilities unfamiliar with the expanding environmental service industry may find it difficult to identify the specific expertise of various remediation contractors.

A recent product from EPRI's Fuel Science Program, *Database for Hydrocarbon-Contaminated Site Remediation: Software and Manual* (GS-6812), provides a guide to environmental service contractors in the United States, broken down by EPA region and including qualifications, references, personnel information, and information on facilities and sales.



In compiling the database, EPRI-sponsored researchers obtained information on environmental service firms through an extensive survey questionnaire, then designed a program that allows users to retrieve from the database the companies that meet their specific requirements. Residing on diskettes that run on IBM XT/AT or compatible personal computers, the database contains information on nearly 200 firms. The retrieval system allows users to identify contractors that satisfy the minimum requirements in a specific category or all contractors meeting the minimum requirements in a set of categories. The database program is self-contained, and no additional software is required to use it.

The initial focus of the project was the wastes from manufactured gas operations, but the organizations included offer a wide variety of environmental services. "This database provides utilities with a practical guide to the many firms involved in different aspects of site remediation," says project manager Conrad Kulik. "It allows users to identify organizations working in their region, compile a list of references, and apply other valuable information in narrowing the field for contractor selection." ■ *EPRI Contact: Conrad Kulik, (415) 855-2818*

Slide Show Aids EMF Education

Utilities are increasingly being asked to reply to inquiries about possible health effects of electric and magnetic fields. An EMF slide show recently released by EPRI's Environment Division is proving to be a useful tool for member utilities in making presentations on the subject to government agencies, public organizations, and their own employees.

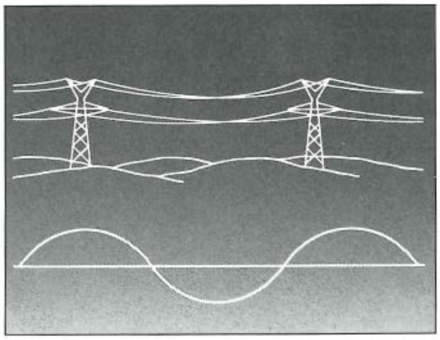
Entitled "Current Studies of Possible Health Effects of Exposure to Power-Frequency Electric and Magnetic Fields" (EN.3009.11.89R), the set of thirty 35-mm color slides reviews the current knowledge of EMF health effects and describes EPRI's research program. The package includes a script to help speakers present and interpret the slides.

According to EPRI's Leonard A. Sagan, program manager for EMF studies, the slides and accompanying text were developed to allow utility speakers to pick and choose from the collection to tailor their presentations to the knowledge and interests of particular audiences. "Speakers may also choose to augment the slides with slides of their own," he says.

That's the approach taken by a number of utilities that have used the slide package. "We've used the EPRI slides along with our own materials to make presentations more specific to our geographical region," says Paul Zweiacker of TU Electric. "For example, if you show an audience a slide of a transmission line that's in their area, it means more to them than if you show them one in another state." Zweiacker has used the EPRI slides during presentations to his utility's customer service and communications departments, as well as to university instructors, civic groups, and technical organizations.

Harry Enoch, manager of research and development at East Kentucky Power Cooperative, says he has used the slides for internal presentations to his utility's EMF task force, which includes personnel from the communications, research, legal, and transmission and distribution departments. The slide and script package, he says, "is a very helpful format for putting out information. We're considering using the material as part of our education program for all employees."

Several EMF specialists commented that because the EMF issue is developing rapidly, it is a challenge to stay current on the subject. "It would be helpful to update this material as new information becomes available," says Enoch. According to EPRI's Sagan, the slides will be augmented from time to time with new material, such as information on reproductive effects or studies related to EMF.



Utility speakers may complement the slides with EPRI-produced videotapes and printed material, according to Steven Lindenberg, the Environment Division's manager of technology transfer. For example, "Electric and Magnetic Fields: Human Health Studies" is a four-page briefing that can be distributed to slide show audiences. ■ *EPRI Contact: Leonard Sagan, (415) 855-2585, or Steven Lindenberg, (415) 855-2736*

Advanced Nuclear Power Plants

Utility Evaluation of Advanced Nuclear Systems

by Ed Rodwell, Nuclear Power Division

ABSTRACT *U.S. electric utilities consistently identify nuclear energy as a significant and favorable source of future electricity generation and urge maintenance of the nation's advanced reactor development program. The program includes development of advanced versions of the high-temperature gas-cooled reactor and the liquid metal reactor as potential supplements to advanced versions of the light water reactor in a future U.S. nuclear plant deployment program. A team of senior utility personnel has evaluated the latest power plant designs and endorsed their continuing development.*

A redesign effort in recent years has produced advanced versions of the high-temperature gas-cooled reactor (HTGR) and the liquid metal reactor (LMR) that may assume a prominent role in the future of nuclear power. The advanced HTGR (Figure 1) was designed by an industrial team led by General Atomics, and the advanced LMR (Figure 2) was designed by a team led by General Electric. Both designs are being funded by the Department of Energy.

To provide a utility industry evaluation of the current U.S. reactor designs based on the HTGR and LMR concepts, EPRI pulled together an evaluation team of senior nuclear utility personnel under the chairmanship of Sol Burstein, the recently retired vice chairman of Wisconsin Electric Power. Commonwealth Edison, Florida Power & Light, Northern States Utilities, Pacific Gas and Electric, Philadelphia Electric, Southern California Edison, and the Tennessee Valley Authority were the other nuclear utilities that contributed members to the team. Staff support was provided by EPRI and its consultants. The evaluation addressed three broad technical topics: plant safety and licensability, plant operability (including maintainability, reliability, and availability), and fuel and fuel cycle.

Safety and licensability

The team found that both the HTGR and the LMR enable the designer to be very responsive to the NRC's call, in its advanced nuclear power plant policy statement, for simplified shutdown and decay heat removal systems, the use of passive responses to off-normal conditions, longer time constants to allow more time before safety system activation, reduced requirements for operator actions, independence of the safety system from the balance of plant, and reduced radiation exposure of plant personnel. For the HTGR, key factors contributing to this behavior are the high-temperature capability of the fuel particle coating, the large thermal capacity of the graphite moderator, and the noncorrosive nature of the helium coolant. Key factors for the LMR are the large thermal capacity of the sodium coolant inventory, the nonpressurized condition of the coolant, and the noncorrosive nature of sodium.

The team found that the HTGR and LMR plant designers had built sufficient margins into the current designs to meet the NRC's additional criteria for the elimination of detailed off-site evacuation plans and exercises. The safety margins also meet the NRC's maximum radioactive release criteria without reliance on a containment surrounding and independent of the reactor coolant boundary. The utility industry team drew attention to the possibility that the precedent set for such a containment by the current LWR plants may make its absence in future plants difficult to justify, even though it would not be needed to meet the quantified and stringent regulatory criteria. Development and costing of fallback containment options were recommended and have since been addressed by the designers.

Operability

The team concluded that the designers had developed the plant designs with enough depth and backup R&D data to ensure that the plant systems would operate essentially as designed. The team identified plant equipment particularly in need of comprehensive demonstration to solidify utility confidence in operability. For the HTGR, the necessity of demonstrating the refueling equipment was stressed because of the large number of movements involved and the dependence of the plant restart date on equipment reliability.

For the LMR, demonstration of the steam generator was stressed because of the dependence of plant availability on the rarity of small leaks of water and/or steam into the sodium.

The team recognized that several of the HTGR and LMR characteristics related to plant licensability—simplified shutdown and decay heat removal systems, the use of passive responses to off-normal conditions, and the noncorrosive nature of the reactor coolants—have served to reduce the number of auxiliary systems and enclosed components that must be operated and maintained in order to ensure high plant availability. This reduction in the number of components is partially offset, however, by the modular approach that has been adopted, which calls for forming a large power plant from several small reactor steam-raising units (equivalent to 135 MWe for the HTGR and 155 MWe for the LMR). The team concluded that determining the optimal reactor capacity was a complex task that warranted more study.

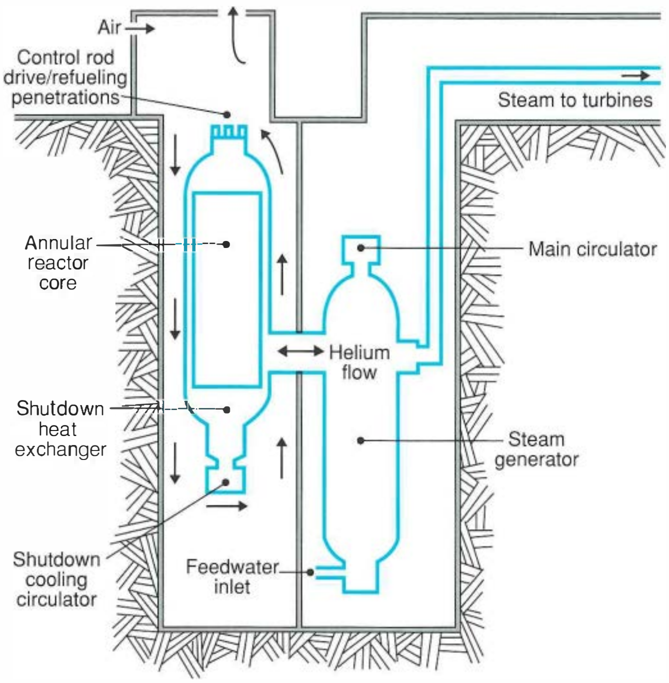
Fuel cycle

It is in terms of fuel and fuel cycle that the HTGR and the LMR differ most, both from each other and from the LWR. The distinctive feature of the HTGR fuel is its coated-particle form, in which kernels of fuel are coated with multiple layers of carbon and silicon carbide. The coating selection and application technology evolved during the U.S. and German HTGR development programs.

Tests on the current version indicate that the coating retains its integrity and impermeability during the kind of transient temperature rise that could result from severe accidents, and that fission product retention is maintained. Fission product release is thereby limited to that caused by manufacturing contamination and defects. One objective for the development program identified by the utility team is to demonstrate that the particles can be manufactured and inspected on a commercial scale to the quality required. An associated challenge is to develop a production line that achieves a fuel cycle cost that can compete with the alternative nuclear fuel cycles.

The distinctive feature of the LMR is that it

Figure 1 Reactor steam-raising equipment of the modular high-temperature gas-cooled reactor design. The heat transport medium is pressurized helium gas, and the thermal capacity is 350 MWth, sufficient to generate 135 MWe.



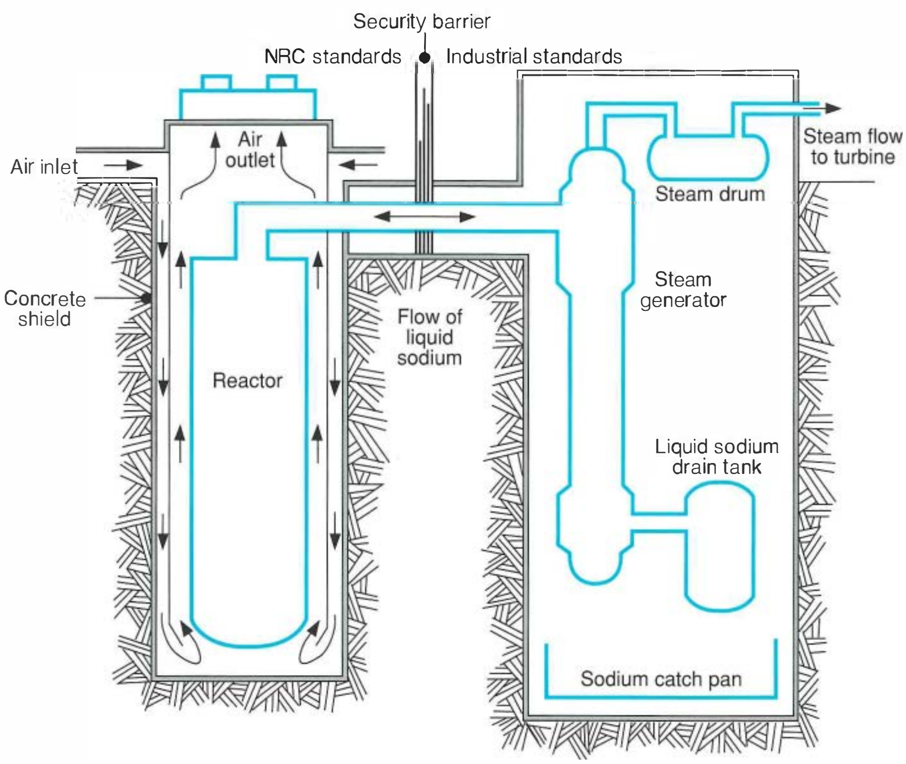


Figure 2 Reactor steam-raising equipment and enclosing structures of the advanced liquid metal reactor design. The heat transport medium is unpressurized liquid sodium, and the thermal capacity is 478 MWth, sufficient to generate 155 MWe.

breeds as much fissile material as it consumes. The effect will be to encourage the processing of spent LMR fuel, both to multiply the heat extracted per ton of uranium and thereby protect the plant owner from demand-induced inflation of the price of uranium (which may arise in the later years of any new plant) and to return the long-life radioactive species to the reactor for transmutation and thereby simplify the disposal of high-level radioactive waste and reduce disposal costs. This latter benefit also accrues to any spent LWR fuel used as a source of fissile material to start up an LMR. The prime objectives for the development program identified by the utility team are to demonstrate the metallurgical endurance of the preferred fuel pin design, which incorporates the fuel in metal form, and to demonstrate the economic superiority of the metal fuel process over the fallback oxide fuel process. DOE's metal fuel development program is being conducted by Argonne National Laboratory.

Current status

The utility team concluded that both plant designs are viable representations of their respective concepts and that their refinement and detailing should be continued. Specific comments and recommendations provided for consideration by the HTGR and LMR program participants are discussed in EPRI reports NP-6644, -6647, and -6676.

Under EPRI coordination, utilities are continuing to evaluate and make recommendations on the evolving designs. In an in-depth review of the HTGR, to be completed shortly, Duke Engineering and Services, Commonwealth Research, and Yankee Atomic Electric will identify the design's strengths and weaknesses, make prognoses for licensing and utility deployment, and recommend improvements to the R&D program.

As for the LMR, the Burstein team—with added participation by Texas Utilities, Wolf Creek Nuclear, and Yankee Atomic Electric—has already visited the designer twice since the initial evaluation in order to assess progress. The team has noted significant improvement in the applicability of the design to utility systems in response to its recommendations.

Demand-Side Planning

Regulatory Incentive Mechanisms for DSM

By Phil Hanser, Customer Systems Division

Throughout the United States, utilities, regulatory commissions, and intervenors are discussing the use of incentive mechanisms to encourage the development of demand-side management (DSM) programs. Several states have recently enacted incentive mechanisms; others have mechanisms in various stages of development. The executive committee of the National Association of Regulatory Utility Commissioners has recently endorsed the concept.

With cosponsorship from the Edison Electric Institute, EPRI held a workshop in August 1989 to explore the concept of DSM incentive mechanisms. It was attended by some 40 utility managers. The workshop proceedings are available as EPRI report CU-6840. This article, which draws on material prepared by John H. Chamberlin of Barakat & Chamberlin, Inc., summarizes the major issues reviewed.

The incentive proposals under consideration take many forms. Some tie a DSM incentive to estimates of avoided supply-side costs. Others follow a more traditional formula involving rate of return on rate base. Still others attempt more radical changes in the overall ratemaking procedures (for example, by providing incentives to reduce sales via any means, thereby discouraging growth in energy sales). Missing from many discussions of such proposals has been a thorough understanding of the financial disincentives associated with DSM expenditures. One way to evaluate any potential incentive mechanism is to consider the extent to which it "cures" these disincentives.

The major direct financial disincentive involves a basic relationship between kilowatt-hour sales, utility revenues, and profitability, and it is directly tied to the cost-effectiveness test used to select DSM programs for implementation. Some types of DSM programs (e.g., strategic conservation) reduce kilowatt-hour sales and hence reduce revenues. This reduction in revenues may or may not result in a reduction in profits. Revenue reduction can actually accompany an increase in profits if costs fall by a greater amount than revenues fall.

Thus the key relationship from a profitability viewpoint is between marginal costs (the measure of how much costs fall when sales are reduced) and marginal prices (the measure of how much revenues fall when sales are reduced). When marginal costs are greater than marginal prices, profits tend to rise when a DSM program reduces sales. When marginal costs are below marginal prices, then sales reductions tend to decrease profitability. (It should be noted that in the real world marginal costs and, to a lesser extent, marginal prices vary by season and time of day; therefore, the relationship between costs and prices is not so clear-cut.)

This effect on earnings potential is a key reason why many utilities favor rate impact measure (RIM) cost-effectiveness tests for the selection of DSM programs. (These are also known as nonparticipant or no-losers tests.) Programs will pass a RIM test when marginal costs exceed the cost of the program plus the marginal price—in other words, when the program tends to be profitable. In addition, the test ensures that rates to nonparticipating customers are not forced up as a result of the program. Many states require a less stringent test that permits conservation and efficiency programs to be adopted when marginal costs are lower than marginal prices. When this less stringent test is used to select programs, there is potential for reductions in profitability.

In many jurisdictions, ratemaking practices make even this basic relationship complex. The contribution to earnings from sales at any time is influenced not just by the relationship between the marginal price and the marginal cost, but also by the manner in which changes in sales affect revenues. For example, in states where an automatic fuel adjustment mechanism is utilized, a reduction in sales translates into a net revenue loss equal to the marginal price minus the average fuel cost during the month. Since the average fuel cost is likely to be less than the marginal energy cost, sales-reducing actions can produce reductions in net revenue even when the marginal price appears to be greater than the marginal cost. The relationship between DSM activities and profitability also depends on whether rates are based on a historical test year (as is generally the case) or on a future test year. These factors are discussed below.

ABSTRACT *While demand-side management programs can be an effective and attractive element of a utility's resource plan, under some circumstances they can lead to a reduction in net earnings. Many in the industry are proposing and evaluating alternative incentive mechanisms to redress this problem. Rather than imposing an arbitrary mechanism with uncertain results, it makes sense to establish one that specifically "cures" all curable disincentives. Disincentives that cannot be directly redressed within the mechanism can be remedied through the provision of an additional bonus in excess of cost. EPRI and the Edison Electric Institute sponsored a workshop to explore various incentive alternatives and the issues involved.*

Direct financial disincentives

Looking beyond the basic relationship into specific issues, there are three ways utilities can suffer reduced earnings by investing in DSM programs. The first is through lost revenues. Any DSM program that reduces the overall level of sales may also result in a loss of revenues. The extent to which this is an issue varies from state to state and depends most strongly on whether rates are based on historical test year values or on projected future sales. In states using historical test years, DSM program impacts that depress energy sales below the test year level result in revenue losses between rate cases but not permanently. Consider, for example, the following simplified example:

Test year: 1988
Test year sales: 1,000,000 kWh
Revenue requirement: $100,000
Average 1989 rate: 10¢/kWh
1989 DSM sales reduction: 1000 kWh
Realized 1989 revenue: $99,900

The $100 in reduced revenue is "lost," but the loss does not continue beyond the next rate case. If, for example, 1989 is chosen as the new test year at the time of the next rate case, the 1000-kWh sales reduction is built into the rates and is essentially recovered from then on out. Additional revenue losses occur if new DSM impacts occur in the future.

In some states, the revenue losses can be partially considered; that is, they are recovered to the extent that they are not offset by sales increases unrelated to DSM activities. This recovery is incomplete, however, since the unrelated sales increases would have happened in the absence of DSM activities.

In jurisdictions using future test years, the amount of the revenue loss depends on how much (if any) of the actual DSM sales reduction was included in the projected test year sales. If the reductions were fully planned and accounted for, there is no revenue loss between rate cases.

The second way utilities can suffer reduced earnings by investing in DSM is through the underrecovery of expenditures. Utilities may not fully recover the actual DSM program expenditures for three reasons:

- Test year accounting practices. Particularly in states using historical test years and in cases where DSM expenditures are increasing, costs will be underrecovered. Rates include only last year's DSM costs, and next year's costs will be greater. The problem is lessened in states that use future test years, but it still may occur if program costs are higher than anticipated (e.g., if more customers than those targeted participate).
- Timing of cost recovery. For many utilities, DSM expenses are recovered substantially after they are incurred, and no interest is collected on the costs. Thus there is a loss of carrying charges on the outlays.
- Factors beyond utility control. Some utilities worry that some DSM expenditures may be disallowed for reasons they cannot control—for example, if target levels of load reduction are mandated and are not achieved because of mild weather conditions.

The third way investing in DSM can result in

Table 1
ELEMENTS OF DSM INCENTIVE MECHANISMS

Element	Type of Disincentive	Proposed Incentive Mechanism
Program cost recovery	Test year amounts below current expenditures	Rate-basing DSM
	Loss of time value of money	Escrow accounting
	Risk of nonrecovery	Carrying charges on deferred amounts
		AFUDC-type return
		Use of future test year
Revenue impacts	Loss of revenues resulting from conservation	Electric Revenue Adjustment Mechanism
	Loss of contribution to fixed costs and earnings	ERAM on a per-customer basis
		Recovery of prior lost revenues based on measured savings
		Recovery of anticipated lost revenues based on forecast savings
		Adjustment of test year for forecast savings
		Use of shorter intervals between rate cases
"Pure" incentives	Loss of opportunity for growth	Rate-basing DSM with bonus return
	Regulatory risk	Bonus return on entire rate base
	Market acceptance risk	Percentage markup on expenditures
	Competitive risk	Bonus tied to megawatt target
	Balance sheet risk	Share of gross avoided cost
		Share of net avoided cost

reduced earnings is through lost opportunities for additional revenue; that is, DSM expenditures can decrease the opportunity for returns on invested capital. This can occur in one of two ways:

- Substitution of capital for expense items. If DSM expenditures are not rate-based, then purchasing the equivalent DSM resource reduces the overall return—it basically substitutes an expense item for a capital item.
- Reduction in other attractive investments. Besides affecting the opportunity to earn a "normal" return, DSM expenditures can affect opportunities for utilities to earn greater returns between rate cases. These opportunities involve cost-saving actions (investments in efficiency), power sales, and the like. DSM expenditures that reduce these kinds of attractive investments—either by reducing the amount of available capital or by reducing sales—reduce earnings below what they would otherwise have been.

Indirect financial risks

In addition to the direct financial risks of DSM expenditures, there are also several indirect ways in which DSM activities can reduce earnings. One indirect risk involves broad regulatory review. To the extent that DSM program results are not as predictable as those of other programs (and hence cannot be accounted for as precisely in ratemaking) or that programs undertaken now are determined not to be needed when reviewed in the future, broad penalties could result—for example, reductions in overall rates of return (in addition to disallowances of some program costs, as discussed above).

A second indirect risk involves effects on competitive markets. To the extent that DSM programs fail RIM tests, their implementation will raise the average level of rates. Thus, even if all the financial disincentives are cured through incentive mechanisms, there is still a concern that raising rates over the level they would otherwise be is undesirable in competitive markets. The effect could be to drive away incremental customers or sales, with consequent loss of contributions to margin.

Additional sales losses are a third indirect risk. Suppose conservation and efficiency programs are highly successful and that costs are fully recovered. The success may encourage more customers to engage in similar actions, resulting in unanticipated lost sales and associated margins without cost recovery.

Liability issues surrounding DSM programs are a fourth indirect risk. Some utility managers are concerned, for example, about the general kinds of liability incurred when work is done on a customer's premises, about the possibility of antitrust litigation (e.g., restraint-of-trade suits by equipment suppliers or installers), and about product liability. Even when a utility is found to be faultless, the costs incurred in the form of insurance premiums and legal defense costs may be substantial.

Developing incentive mechanisms

Specifying the nature of the potential disincentives allows a clearer and more focused discussion of the development of incentive mechanisms. A straightforward approach to providing DSM incentives is to provide sufficient mechanisms to eliminate the sources of disincentives. The workshop participants agreed that there are four key disincentives policymakers must address in developing a compensatory incentive mechanism. They must (1) allow for the recovery of net lost revenues; (2) allow for the timely recovery of expenses; (3) provide a positive return above cost to compensate for risk; and (4) ensure that no new disincentives are added through the adoption of procedures to collect the incentive.

The last requirement is as important as the first three. When developing an incentive mechanism, it is critical to consider such factors as how program impacts are measured; whether postprogram evaluation can affect the prior collection of incentive revenues; and whether incentive awards affect broader issues of profitability (e.g., if overall rates of return are considered). In short, the manner in which a mechanism is implemented is as important as the mechanism's elements.

Table 1 illustrates the key elements of a comprehensive incentive mechanism: lost revenue recovery, timely program cost recovery. and positive return above cost ("pure" incentives). Lost revenues can be recovered in at least two ways. In states using future test years, a mechanism like ERAM (the Electric Revenue Adjustment Mechanism) can be established. This consists of a balancing account that recovers any nonfuel revenue variation from the revenues forecast in base rates. Alternatively, a calculation of nonfuel revenues lost specifically because of DSM activities can be made. This can be done in a way that imposes additional risk for the utility or in a way that does not. In the former case, an evaluation of actual load impacts after the fact can be used as the basis for the calculation. In the latter case, to minimize additional risk (and to ensure symmetry with cost recovery in the program implementation decision), agreed-on assumptions for load impacts can be used in making the calculation. An automatic mechanism (like a fuel adjustment clause) can then be established, with the amount increasing as new participants are added to the program. If further evaluations lead to revisions in these planning impact assumptions, the mechanism can be revised for revenue collection on a forward-looking basis.

In the area of program cost recovery, utilities must have relatively strong assurance that all costs will be recovered and that recovery will be synchronous with expenditure. Recovery by means of an automatic adjustment mechanism provides this assurance. As with fuel adjustments, it could be subject to later regulatory review and scrutiny.

Because some DSM disincentives are not curable, an effective incentive mechanism would provide a positive return. There are several ways this can be accomplished:

- Providing a return as if DSM costs were rate-based. This could be several points above the allowed rate of return on other investments.
- Providing for a sharing of net avoided costs due to a DSM program (i.e., the costs avoided by the program minus the direct program expenditures). Several commissions have allowed or are considering shared avoided costs in the 30–50% range.
- Establishing a bonus based on achieving DSM load targets and tied to the overall level of expenditures or other factors. The bonus could be either an increase in the overall rate of return or a level of revenues based on a formula involving the rate at which the target was achieved or some other indicator of program efficiency.

Finally, if the overall rate impacts of DSM efforts are important for either equity or competitive reasons, the cost recovery can be isolated and allocated to each class in proportion to the DSM program's costs and benefits.

Fossil Power Plants

Variable-Pressure Operation for Cycling Units

by John A. Bartz, Generation and Storage Division

Because of its benefits for plant operations, more and more U.S. utilities are interested in the use of variable-pressure operation (VPO) for fossil cycling units—a common operating practice in Europe and Japan. Several VPO retrofits have already been successfully implemented in the United States, including units of Houston Lighting & Power, Pacific Gas and Electric, and American Electric Power. In fact, at least 14% (over 170 units) of large U.S. fossil fuel units now use VPO.

EPRI has begun a two-part research project that will make it easier for utilities to retrofit units for VPO (RP1403-16). In the project's recently completed first phase, EPRI surveyed U.S., European, and Japanese utilities to establish the state of the art of VPO and published the resulting database in *Variable-Pressure Operation: An Assessment* (GS-6772). In the project's second phase, EPRI will follow the retrofit of an existing unit to VPO, assessing its advantages and disadvantages and estimating its costs and benefits. This will augment work completed under RP1184 on the cycling of baseload fossil units.

VPO benefits

Most fossil fuel units in the United States maintain a constant boiler pressure and use turbine control valves to modify unit output. This practice results in significant throttling losses at part loads (e.g., more than a 5% heat rate loss at 20% load for one unit). VPO uses turbine throttle pressure to modify unit output, reducing these losses.

There are two modes of VPO, full and hybrid. In full VPO, control of the unit output is accomplished entirely by varying the throttle steam pressure. Turbine control valves remain at or near the full-open position and are only slightly modulated for control. In hybrid VPO, initial load reductions (from maximum loads) are achieved by closing the turbine control valves while maintaining full throttle pressure. Further load reductions are achieved by reducing the throttle pressure at a constant control valve position. The transition point between constant- and variable-pressure operation is normally in the range of 60–85% load.

For EPRI's database on VPO, the two contractors (Burns and Roe, Inc., and Gilbert/Commonwealth, Inc.) surveyed U.S., European, and Japanese utilities and manufacturers. The database verifies that both full VPO and hybrid VPO have several significant advantages over constant-pressure operation for cycling units. These advantages include

ABSTRACT *Fossil fuel power plants used for cycling duty must be able to meet the demands of reduced-load operation, decreased startup times, and increased ramp rates economically and with minimal wear and tear on steam-cycle components. Converting constant-pressure units to variable-pressure operation (VPO) can satisfy the need for flexible and efficient cycling. VPO is used extensively in both Europe and Japan, and several U.S. utilities have converted existing units to VPO. EPRI has recently published a survey on the state of the art of VPO and will now document the specific benefits of a VPO conversion.*

extended turbine life, improved operating flexibility, and the potential for improved unit heat rate.

Full VPO can extend turbine life (by a factor of 10 or more in some cases) because the turbine first-stage exit temperature remains nearly constant as unit output changes, which minimizes thermal stresses. Conversely, in constant-pressure operation, the first-stage exit temperature decreases as unit output decreases, which imposes thermal stresses on the turbine. Hybrid VPO is a compromise between these two cases: the temperature changes are smaller than in constant-pressure operation but larger than in full VPO.

The EPRI database confirms that VPO can enhance plant operating flexibility. For example, increased main-steam temperature can reduce the minimum loads for units limited by low steam temperatures. Furthermore, operators can use combinations of variable- and constant-pressure operation during unit shutdown and startup to better match steam and turbine metal temperatures, thereby reducing startup times (by as much as 30–40% in some cases).

For a unit using VPO at part load, there are three potential effects that can reduce unit heat rate: improved high-pressure-turbine efficiency, reduced boiler feedpump power, and higher steam temperatures. Although the decrease in available energy that is due to reduced pressure may partially offset these effects, VPO can result in a net heat rate reduction. Reducing the throttle pressure at part load instead of using the turbine control valves reduces throttling losses, improving high-pressure-turbine efficiency and heat rate. In many cases, decreasing the pressure under VPO reduces pump power consumption in units with variable-speed-drive boiler feedpumps, which also improves heat rate.

Finally, VPO can improve heat rate by maintaining high main- and reheat-steam temperatures over a wider control range than in constant-pressure operation. At reduced pressure, the increase in main-steam temperature is greater for a given level of energy absorption. Hence, boilers can produce hotter main steam when operating at reduced pressure. Moreover, at part load under VPO, high-pressure-turbine exhaust steam (cold reheat steam returning to the boiler) is hotter than under constant-pressure operation. With hotter incoming steam, the boiler produces hotter reheat steam.

EPRI research indicates that these three benefits can result in a net part-load heat rate improvement of 3–4% in units with a full-arc admission turbine and a spiral-wound furnace or drum boiler. This in turn can reduce annual fuel consumption by 1.3–2% for intermediate or cycling units. The benefits of VPO in units with a partial-arc admission turbine may be somewhat lower.

VPO drawbacks

EPRI's database points out some drawbacks associated with VPO, including sluggish boiler load response and increased boiler fatigue stress. Both drawbacks are especially significant for drum boilers, which rely on energy storage for rapid response to small load changes. By reducing storage, operation at reduced pressure diminishes this response, thus necessitating overfiring on load increases and underfiring on load decreases. Steam and metal temperature excursions in the convective pass caused by firing–evaporation rate mismatches often limit the rate of load change, and rapid changes in temperature and pressure lead to cyclical stresses that shorten the lives of boiler components.

Advanced digital control systems that monitor crucial steam and metal temperatures can prevent boiler response problems by helping operators optimize overfiring on load increases and underfiring on load decreases. The careful selection of a hybrid pressure mode and the use of advanced control systems can also help minimize boiler cyclic stress from rapid temperature and pressure changes while reducing turbine cyclic stress.

Typically, subcritical drum boilers can use VPO with little change to major equipment. However, furnaces of most U.S. once-through boilers cannot withstand low-pressure operation without some modification. To permit variable throttle pressure, one of two fundamentally different techniques is usually necessary—spiral-wound-furnace retrofit or superheater valve replacement. Spiral-wound-furnace retrofits have been carried out at two U.S. subcritical units and two Japanese ones. Superheater throttling valves have been modified at some supercritical once-through units to implement VPO.

Experience with VPO

In addition to covering U.S./U.S.-designed VPO units, EPRI's survey included 126 European/European-designed units and 75 Japanese/Japanese-designed units. The survey revealed that, partly because of different loading requirements, VPO is used differently in Europe and Japan than in the United States. Increasingly in Europe and Japan, new fossil units are being designed for daily start-stop operation with full VPO. In fact, the portion of Japanese oil-fired and coal-fired units designed for VPO increased from 30% in 1980 to 100% in 1987. Because of the need for high efficiency and rapid response, most of these units use once-through supercritical boilers with spiral-wound furnaces.

In the United States, most existing fossil steam plants were designed primarily for baseload, constant-pressure operation. Because of changing loading requirements, many of these older plants are now being operated in a cycling mode. EPRI's research indicates that more than 170 U.S. units—about 14% of the units larger than 100 MW—are now operating under some form of VPO. Most of these units are subcritical units. A very small number of supercritical units operate under VPO in the United States.

Half of the U.S. units using VPO were retrofitted to the capability. Of those retrofitted, 80% required no changes to the boiler; most of the retrofits involved drum units, which require only control system upgrades. Plant operators using VPO report a variety of improvements: 89% report improved heat rate, 58% an increase in load change rate capability, 60% a reduction in startup time, and 38% a reduction in shutdown time.

Future work

Retrofits of subcritical units are currently of most interest to U.S. utilities, and for the second phase of its VPO project, EPRI plans to document the upcoming retrofit of Duquesne Light's Cheswick Unit 1 to VPO operation. The conversion is scheduled for late 1990. On the basis of studies of past retrofits, EPRI will also develop guidelines for utilities on converting supercritical units to VPO operation. Depending on utility interest, EPRI may perform a case study of a supercritical VPO retrofit. This work will augment studies of Pacific Gas and Electric's Moss Landing Unit 7 under RP1184.

System Safety and Licensing Analysis

Reactor Set-Point Analysis Methodology

by Govinda Srikantiah, Nuclear Power Division

Set-point methodology offers utilities the means to establish appropriate and justifiable limits for reactor monitoring and protection system set points. If existing set points are too conservative, utilities may be faced with operational constraints that limit power output or plant maneuverability. In some cases, the utility may have to implement costly plant modifications or other vendor-supplied alternatives to alleviate the situation. By having a definitive set-point methodology available, utilities will be able to make cost-effective decisions on whether to make plant modifications or implement set-point changes to attain the desired operating margin.

Each of the nuclear steam supply system vendors has developed a unique method of determining set points. Though the set points established by these various methods satisfy the same regulatory requirements, differences in plant design, operation, and response characteristics have led to substantial differences in approach. While utilities are familiar with the general aspects of set-point methodology used by vendors, the details and applications may be proprietary or may not be clearly documented. As part of the EPRI-sponsored Reactor Analysis Support Package (RASP) project, a generic set-point analysis methodology was developed (RP1761). It is now being demonstrated at various types of nuclear plants for set-point analysis and modification (RP2973); several applications are in progress, and some are complete.

The process of set-point analysis begins with the identification of the limiting transient events that influence the particular set point most and the establishment of event acceptance criteria (such as operating limits on reactor coolant system pressure), which are the bases for accepting the results of safety analysis. The remaining important tasks in the process are the analysis of plant performance characteristics to establish inputs to safety and performance analyses and the treatment of uncertainties in the inputs and methods. Modeling, correlation, system, and measurement uncertainties must also be considered. The key to the entire process is the treatment of the uncertainties to ensure conservatism in the event analysis.

In the deterministic approach to treating uncertainties for most current set-point analyses, all uncertainty components are assumed to be simultaneously at their design limit values; the result is highly conservative estimates of the figures of merit for an event. The available margin provided by this approach, however, has decreased with more-stringent regulatory requirements, longer fuel cycles, and the need for more flexibility in plant maneuvering.

The statistical combination of uncertainties (SCU) approach, which has been used recently by some vendors, provides a rational basis for the determination of margin and of safety analysis event acceptance limits. The main elements of this approach are the classification of various uncertainties into major groups, the development of a combined un-

ABSTRACT *Reactor set points are those instrument limits, specified in terms of measurable process variables, at which system automatic or operator manual action must be instituted to preserve the assumptions of plant safety analysis and ensure that plant performance requirements are met. Set points thus represent a translation of safety and plant performance analyses into plant operational requirements. Reactor set points must be verified or reestablished as part of fuel-reload analysis, as a follow-up to plant modification, or in response to changes in regulatory requirements. A generic set-point analysis methodology has been developed under EPRI sponsorship.*

certainty distribution for each group, and the use of this distribution to evaluate the event acceptance limits and confidence levels for the selected set-point variable.

Under the set-point methodology applications project, several utilities have applied the RASP methodology combined with the SCU process to their plant set-point modifications. Their objective was to gain margin in order to maintain operational flexibility as well as acceptability from the standpoints of plant licensing and safety. Three applications completed under this project are described below.

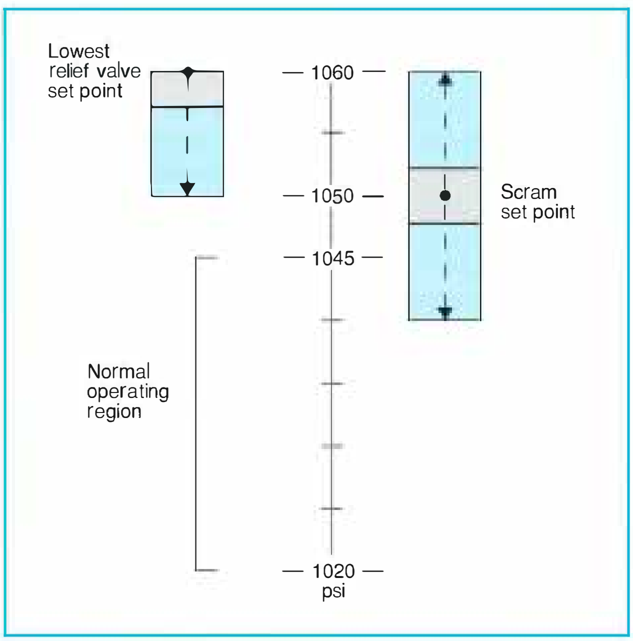


Figure 1 Certain high-pressure set points at the Oyster Creek BWR can overlap because of instrument calibration tolerances (±2.5 psi; gray) and instrument system uncertainties and drift (7.5 psi; color). GPU has used an EPRI-developed generic set-point analysis methodology to modify the set points to eliminate the problem and has submitted the modifications to the NRC for approval.

High-pressure set points

One of the first applications of the EPRI-developed methodology was the modification of the high-pressure set points of General Public Utilities' Oyster Creek BWR. GPU was concerned with the plant's inability to accommodate instrument calibration tolerances and drift without violating technical specifications or potentially overlapping the high-pressure set points. The plant's current technical specifications severely limit set-point options, and in general there is an absence of adequately documented grounds for the existing high-pressure set points. GPU decided to modify them to increase the margin in order to allow for measurement uncertainties, including instrument system uncertainties, calibration error, and set-point drift.

The set-point overlap problem is illustrated in Figure 1. The calibration tolerance of the high-pressure instruments is ±2.5 psi. Instrument system uncertainties and drift can account for an additional +7.5 psi. The scram set point, for example, can therefore move up 10 psi above its nominal 1050 psi, to 1060 psi, and the lowest electromagnetic relief valve set point can move down 10 psi below its nominal 1060 psi, to 1050 psi. Because of this overlap, the relief valves could open before scram occurs. There is also the possibility that the scram set point could overlap with the normal operating range and cause an unintentional scram. GPU is proposing set-point distributions (Table 1) that would eliminate the overlap, allow for drift, and considerably reduce safety valve surveillance reporting requirements. The high-pressure scram set point would be raised to reduce the potential for spurious half or full scrams.

The generic procedure developed under the RASP project, together with plant safety analysis and design information, provided the basis for the development of the plant-specific set-point methodology for Oyster Creek. In the first step of this process, GPU developed a modified RETRAN code model of the Oyster Creek plant based on its license-basis model, and it identified the limiting plant transients that directly affect the high-pressure set points. (As a lead utility in the RASP project, GPU had developed a RETRAN model of the plant as part of its reload licensing effort—see NP-4498, Vol. 10.) The next step was to identify and document the event acceptance criteria. The most limiting requirement identified was an acceptably low probability that safety valves would open during transients. Using nominal technical specification values for RETRAN input, baseline event analyses were performed. Sensitivity studies were then performed to identify the parameters that had the most influence on the high-pressure set points. On the basis of the results, the EPRI STARS code was used to construct a response surface that gives the functional relationship between a set-point variable and the key parameters. The response surface provided the tool for performing the Monte Carlo analyses necessary for SCU to develop the combined uncertainty in the set-point variable—in this case the peak pressure attained in the limiting plant transient.

The goal of the SCU process is to combine the peak-pressure probability distribution with the probability distribution of the pressure at the first-opening safety valve. Since the safety valves are connected in a network, this probability distribution was calculated by using the EPRI PLANETS code, which provides a method for analyzing the performance of a redundant network of valves or instruments. If the combined probability, which is the probability that the increasing pressure during a limiting anticipated transient will exceed the pressure at the first-opening valve, is acceptably low, then the high-pressure set point is within the acceptable range established by applying the event acceptance criteria.

The next step in the process is to select the potential limiting license-basis events that may reach the high-pressure set points and to perform safety analyses in order to verify the adequacy of the new high-pressure set points. For Oyster Creek, the potential limiting events were identified as turbine trip without bypass, feedwater controller failure, and overpressure protection. Using the RASP guidelines, GPU performed license-basis analyses and plant performance analyses and demonstrated that the event acceptance limits are satisfied and the new high-pressure set points are acceptable from both standpoints.

As a result of this extensive study, GPU acquired a good understanding of the plant design basis and operations and developed the analytical basis for reducing the number of safety valves from 16 to 8 while still maintaining design-basis assumptions. GPU has prepared a report documenting its modifications to the technical specifications and has submitted it for NRC review and approval.

Table 1
TECHNICAL SPECIFICATIONS AND SET POINTS FOR HIGH-PRESSURE INSTRUMENTS AT OYSTER CREEK BWR

	Current Specification/ Set Point (psig)	Proposed Specification/ Set Point (psig)
Open safety valve bank 1	1212 ± 1% / ≤ 1224	1212 + 1%, -3% / ≤ 1224
Open relief valve groups B, C, and E	1090/1080	1105/1095
Open relief valve groups A and D	1070/1060	1085/1075
Recirculation pump trip and isolation condenser	1060/1060	1075/1065
High-pressure scram	1060/1050	1065/1055
Alternate rod insertion	NA/NA	NA/1085

Note: The proposed revisions maintain 20 psi between electromagnetic relief valve groups and increase the safety valve tolerance

Operating minimum critical power ratio

Yankee Atomic Electric anticipated a reduction in the operating margin in the minimum critical power ratio (MCPR) associated with longer operating cycles at the Vermont Yankee BWR. The analysis methods applied to determine the existing operating margin, which was approved by the NRC, had used a point kinetics model. Yankee Atomic Electric staff felt that by applying the more accurate one-dimensional kinetics model available in the EPRI RETRAN code, they could obtain enough improvement in the MCPR operating margin to offset the anticipated margin reduction. There was concern, however, as to whether there would be enough conservatism in the calculation to satisfy licensing requirements when one-dimensional kinetics was used in place of the point kinetics model.

Yankee Atomic Electric performed calculations with the RETRAN one-dimensional kinetics model and compared the results with two other sets of calculations: calculations of the Peach Bottom turbine-trip-without-bypass event and the more severe license-basis event that were made with the point kinetics method, and vendor calculations made with one-dimensional kinetics methods. The utility also simulated a recirculation pump trip transient with the RETRAN one-dimensional kinetics model and compared the results with actual data available for the transient.

These comparisons showed that the one-dimensional kinetics model responds accurately. The calculations also showed that use of the model resulted in the expected gain in the transient MCPR margin. In order to demonstrate an acceptable level of conservatism in the determination of the MCPR operating limit, Yankee Atomic Electric used the EPRI SCU methodology to calculate the combined uncertainty due to model and scram-speed uncertainties. To establish the scram-speed uncertainty in the MCPR margin, a response surface was constructed by means of the EPRI STARS code. The RETRAN model uncertainty was determined by means of sensitivity studies. The final value of the MCPR margin was calculated by statistical convolution of the scram-speed and model uncertainty distributions. Furthermore, Yankee Atomic Electric demonstrated that its licensing approach, which is based on RETRAN one-dimensional kinetics and uses conservative values for input parameters, is adequately conservative. This determination was made by comparing the CPR operating limits with the result of the statistical evaluation. The NRC recently approved the utility's methodology.

Safety valve set-point tolerance relaxation

During surveillance testing, safety valves at Pacific Gas and Electric's Diablo Canyon PWR did not meet the current set-point tolerance limit of ±1%. This led to nonconformance reports and costly additional testing of pressurizer and steam line safety valves. PG&E determined the root causes to be set-point drift, test uncertainties, and sticking valves. Solutions considered included improving the test method and replacing valves—both of which are costly and time-consuming—and relaxing tolerance. PG&E decided to use EPRI methodology to justify tolerance relaxation.

After a study of the current technical specifications and records of plant safety and performance, PG&E decided to justify relaxation of the tolerance from the current ±1% to ±3%. The limiting transient for plant overpressure protection was identified as loss of load/turbine trip. PG&E used the EPRI RETRAN code to set up the Diablo Canyon plant model and verified this model against plant data. The utility analyzed the loss-of-load/turbine trip transient with the relaxed safety valve tolerance limits and showed that the proposed ±3% relaxation was adequate to provide plant overpressure protection. PG&E also evaluated other final safety analysis report events that may possibly challenge the safety valve pressure set points and concluded that the tolerance relaxation was conservative.

PG&E has submitted a report to the NRC requesting approval of changes to the Diablo Canyon technical specification on safety valve set-point tolerance. This tolerance relaxation will provide operational flexibility while meeting licensing requirements and will reduce plant downtime by eliminating the additional testing necessitated by the earlier, more-restrictive tolerance limits.

Power Electronics and Controls

Power Quality Test Facility

by Marek Samotyj and William M. Smith, Customer Systems Division

As sensitive electronic equipment proliferates near power-disrupting equipment in residential, commercial, and industrial applications, so do power-related problems. Efforts to alleviate these problems have ranged from expensive power-conditioning equipment to special wiring and grounding techniques. On a case-by-case basis, determining the most cost-effective solution requires an accurate technical understanding of the problem.

In general, there are three basic technical questions to be answered: What is the nature of the disturbance (i.e., point of origin, cause, frequency of occurrence, magnitude, and duration of equipment exposure at the load)? What are the thresholds of load susceptibility as a function of load type, installation method, disturbance magnitude and duration, point of exposure, and operating condition at the time of exposure? And how do load and source interact to mitigate or exacerbate power quality problems?

To answer these and other relevant questions, EPRI—with financial support from the Tennessee Valley Authority—has established the Power Quality Test Facility (PQTF) at the EPRI Power Electronics Applications Center (PEAC). The facility's unique contribution is its ability to perform a complete set of parametric tests to determine the compatibility of common electronic loads with the utility power source. These tests include the generation of steady-state harmonics and also the intermittent short-duration disturbances typical in power systems (e.g., from momentary fault conditions, reclosure operations, and capacitor switching). When appropriate, actual disturbance events captured in the field can be reproduced in the PQTF.

Other laboratories currently perform some compatibility testing of equipment on a limited basis. A rather significant level of effort, in terms of both capital for equipment and specialized software development, is required for full-spectrum testing with the necessary repeatability and data analysis capabilities. The newly established PQTF is assuming a unique role as a comprehensive facility to meet the power quality needs of electric utilities and their customers.

Objectives

In order to fulfill the overall mission of the PQTF, the following specific objectives will be accomplished:

- Develop the capability to conduct four categories of tests related to load and source compatibility (initially up to 5 hp and later up to 100 hp, three-phase, 120/208 or 408 V). The test categories address (1) the impact of customer equipment on utility and customer power line quality during normal operation; (2) the sensitivity of customer equipment and certain utility equipment to intermittent and steady-state power quality disturbances (i.e., momentary interruptions, sags and swells, and harmonic voltage); (3) the sensitivity of customer equipment and certain utility equipment to fast-rise time surges (the IEEE 587 unidirectional and oscillatory surge tests) and high-energy utility capacitor switching transients; and (4) the dynamic interaction of two devices that are both sensitive to, and sources of, power quality disturbances.

- Design and develop an automated data acquisition and control system capable of gathering and analyzing the data necessary to perform a characterization of the equipment under test.
- Develop standard test plans, procedures, and reporting formats for each of the four categories of compatibility tests and modes of facility operation.
- Develop facility operating procedures to ensure safe and reliable testing under all test conditions.

The PQTF houses equipment in which the three-phase line voltages and neutral are isolated from the instrumentation by isolation amplifiers and connected to four voltage-waveform digitizers. These same four voltage signals can be selectively routed through 60-Hz notch filters, under computer control. The power connected to the system under test is routed through four current probes with current amplifiers and four current-waveform digitizers. The output of the system under test is routed in the same manner as the line side. However, in order to determine the sensitivity to various power disturbances exhibited by a system or component under test, a controllable source of ac power must be available.

The heart of the test facility is the 120-kVA, three-phase, 480-V power supply simulator installed in 1989. The three-phase power supply simulator and isolation unit converts the incoming ac power to dc, then remanufactures the ac to power a system under test up to 120 kVA. It isolates the incoming power from the system under test and provides a clean, stable, and controllable power source. The output voltage may be varied between 0 and 520 Vac rms, and the frequency is fully controllable in 0.1-Hz steps from 40 to 500 Hz. Phase relationships may be changed in 1° steps for the full 360° on any or all phases. Output impedance is also controllable. In addition, the unit can produce subcycle voltage variations at its output by varying an input signal.

To further extend the simulation capabilities, three arbitrary-function generators will be employed to create programmable distorted input waveforms. These generators, in conjunction with the power supply simulator, will be able to create waveforms that contain 0.3-ms transients on voltage signals up to 935 V peak. With the simulator and the arbitrary-function generators, it will be possible to simulate outages, sags, swells, limited surges, harmonics, and other waveforms that occur during normal operation in the field.

ABSTRACT *PQTF was recently established at the EPRI Power Electronics Applications Center in Knoxville, Tennessee, to carry out unbiased evaluation of power quality disturbances and impacts. The facility conducts controlled experiments on utility and customer hardware and quantifies both the sensitivity of these systems to power disturbances and their propensity to produce waveform distortions.*

The disturbances may be single events (e.g., voltage sags) caused by such factors as motor starts and stops, utility capacitor bank switching, and short-duration lightning-induced distribution faults. Or the disturbances may instead be in the form of steady-state harmonic distortions created by, for example, an adjustable-speed drive or a bank of fluorescent lights.

The main objectives of the PQTF are to determine quantitatively the impacts of disturbances on electric and electronic equipment and to recommend testing and mitigation alternatives. Establishing equipment response characteristics (data errors, overheating problems, insulation breakdown, improper operation) over the range of likely power supply conditions is the first step in evaluating the penalties of poor power quality. This laboratory information, when coupled with productivity impact estimates collected from field surveys, will begin to shed light on the real costs of power quality problems.

Power quality

A unique capability of the PQTF will involve multievent testing, which is distinguished from single-event testing by its repetitive nature, the need for a real-time decision to store or reject a piece of information, and the need for statistical analysis of the large number of data gathered. Only a facility of national scope can support this comprehensive approach to the power quality problem. The behavior of surge arrestors, for example, could be examined by injecting a single-voltage waveform and recording the current response and energy dissipation. Such a test cannot provide any statistical data over the assigned time period, however. Only testing done repeatedly over the time period can determine the envelope of waveforms representing the range of disturbances that the surge arrestor can handle. This testing approach will also sort out the tolerance of surge arrestors to varying levels of energy content and voltage on the basis of measurements of response to resultant current levels. As an objective source of testing capability, the PQTF can provide a valuable service to utilities, manufacturers, and end users by developing power quality test procedures and specifications, performing multievent testing of equipment, specifying data presentation formats for reporting the results, and automating the testing and reporting processes.

With this information, it will then be possible to develop cost-effective solutions. In some cases, these solutions may involve the application of mitigation equipment (e.g., uninterruptible power supplies, power line conditioners). In other cases, it may be more cost-effective to clean up the root cause of the problem or modify the power supplies in electrical equipment to be less sensitive to power disturbances. This would entail the use of a ridethrough feature for digital clocks, for example, or small uninterruptible power supply circuits built into personal computers.

One of the goals of the PQTF is to promote better understanding of power quality issues and to dispel some misconceptions about how to avoid or correct electronic system grounding problems. The issue of grounding—in particular, how to deal with electrical noise and safety simultaneously—has been recognized as a critical element in utility and electronic load compatibility. Yet the identification and resolution of system grounding problems is complicated by conflicting philosophies. Power-oriented engineers will usually differ from signal-oriented engineers in their perception of common problems and choice of solutions.

Technology evaluation

The Power Quality Test Facility has already started its initial technology assessment efforts. The first project is to evaluate the electric-service susceptibility and performance of the EPRI Frymaster advanced electric fryer with solid-state controller (triac). The following observations were made during the first months of operation:

- The solid-state controller components are conservatively rated as to applied voltage, current, and temperature conditions. Wide steady-state voltage variations, 200% overload currents, and extreme ambient temperature excursions do not affect the performance of the solid-state controller.
- The solid-state controller is compatible with the neighboring electrical systems that are found in a typical restaurant. During controller starts, stops, or steady-state operation, no perceptible electrical interferences were observed. The electric fryer's circuits and controls were then evaluated to assess how well the solid-state controller will tolerate anomalies in electric service (e.g., harmonics produced by other restaurant loads, fast transients coming from lightning). As a result of these tests, changes were made in the control transformer and the surge-suppression circuitry (which protects the triac).

Next, an examination will be made of mechanical packaging options for the present solid-state controller to assess whether subsequent modules can be quickly plugged in or out to minimize the costs of repair parts and labor. Future solid-state controller assemblies could be made interchangeable worldwide. The solid-state controller eliminates the electrical solenoid coil, a common failure mode for existing fryers. In addition, the solid-state contactor does not produce the sparking and metal contact wear produced by electromechanical relays. Therefore, the new fryers may have a longer life and should minimize safety concerns when operated in hazardous environments. Also, as future fast-food preparation specifications become more sophisticated, the solid-state controller may be able to adapt more sensor information to meet product quality control requirements.

The PQTF will offer the opportunity for PEAC, individual electric utilities, and other agencies to collaborate on power quality testing. There are many loads that have broad national significance, such as personal computers and office equipment, arc welders, and adjustable-speed drives. There is sufficient regional and national interest in power quality for the establishment of a number of consortia to pursue the testing of power quality equipment. Many utilities want to be able to recommend a particular class of equipment (e.g., a VCR or a digital clock) to their customers on the basis of its ability to ride through power quality disturbances. Others want to be in a position to recommend or recommend against particular classes of power-conditioning equipment (e.g., a transient-surge suppressor or a single-phase uninterruptible power supply for critical loads). A power quality equipment testing program led by PEAC would enable utilities to make such recommendations.

Collaborative testing

By September 1990, PEAC will develop a mechanism for integrating its own capabilities with those of other existing or developing test facilities (e.g., the National Institute of Standards and Technology; the Canadian Research Council; Wichita State University, together with Kansas Electric Utilities Research Program; and California Polytechnic State University, together with Pacific Gas and Electric). This mechanism, called power quality collaborative testing, will provide better coverage, while saving capital investment dollars where duplicative facilities can be avoided.

Two such networking efforts will be established: the PQ Equipment Sensitivity Testing Program and the PQ Equipment Impact Testing Program. The sensitivity testing program will begin in October 1990 with a series of residential appliances—VCRs, digital clocks, microwave ovens, and transient-surge suppressors. Once the residential program has verified the adequacy of the test methods, data analysis methods, and report formats, the testing program will be extended to commercial and industrial products. Personal computers and point-of-sale devices are obvious choices for the former; programmable logic controllers and electric motors, for the latter.

The impact testing program will be initiated in January 1991 along the lines of the sensitivity testing program. A residential component will be established first. The same appliances that were tested for sensitivity will be tested for impact (propagation of power disturbances); in addition, several variable-speed motor-driven appliances (e.g., power tools, vacuum cleaners, kitchen appliances) and single-phase uninterruptible power supplies will be tested. Fluorescent lighting, metal halide lighting, copying machines, and power line conditioners will be added to cover the commercial sector. Industrial equipment will include arc welders, adjustable-speed drives, and uninterruptible power supplies.

Manufacturers concerned about the power disturbance propagation or sensitivity characteristics of these products will also be able to avail themselves of power quality collaborative testing. Test results should provide them with a means of developing a competitive edge in the design of electrical products.

The PQTF will offer another important benefit to electric utilities: hands-on courses that will train utility engineers to perform tests and analyze results. They will also be able to test electrical equipment on-site. A pilot training course is scheduled for late 1990.

New Contracts

Project	Funding/ Duration	Contractor/EPRI Project Manager
Customer Systems		
Development of Demand-Side Management Planning Package (RP1485-15)	$101,500 10 months	Electric Power Software, Inc./*P. Hanser*
Microwave Fabric Dryers (RP2034-39)	$100,200 14 months	Thermo Energy Corp./ *J. Kesselring*
EPRI Computer-Aided Lighting Design (RP2285-19)	$109,200 14 months	Hart, McMurphy & Park, Inc./*K. Johnson*
Water Loop Heat Pump Design Guide and Brochure (RP2480-13)	$72,300 9 months	Charles Eley Associates/ *M. Khattar*
Industrial Program Environmental Analysis and Support (RP2662-7)	$50,000 11 months	Tem Associates, Inc./ *L. Harry*
Production of Technical Commentaries and Technical Applications (RP2782-11)	$149,900 10 months	ProWrite, Inc./ *A. Amarnath*
Real-Time Pricing Control of Commercial Thermal Storage (RP2830-94)	$119,400 13 months	New York State Energy Research and Development Authority/*L. Carmichael*
Testing of Improved Dual-Fuel Heat Pumps (RP2868-5)	$65,700 4 months	ETL Testing Laboratories, Inc./*C. Hiller*
Electrical Systems		
Voltage Dip Computation Using Direct Stability Analysis (RP2206-6)	$70,700 11 months	Georgia Tech Research Corp./*M. Lauby*
New Silicons and Polyphosphazenes as High Dielectric Constant Polymers for Capacitor Applications (RP2986-1)	$68,300 17 months	Rensselaer Polytechnic Institute/*B. Bernstein*
Development of Solid-State Current Limiter and Circuit Breaker (RP3155-1)	$318,900 12 months	Westinghouse Electric Corp./*H. Mehta*
Capacitor Switched-Inductor Pair for Variable Series Compensation (RP4000-20)	$68,500 22 months	Clarkson University/ *D. Maratukulam*
Advanced Voltage Control Systems (RP4000-22)	$100,000 23 months	Southern Illinois University/*D. Maratukulam*
Magnet Replicas and the Very Incomplete Meissner Effect (RP4000-23)	$50,900 12 months	University of Houston/ *M. Rabinowitz*
Lease for the Waltz Mill Underground Cable Test Facility (RP7801-6)	$1,470,000 60 months	Westinghouse Electric Corp./*J. Shimshock*
Generation and Storage		
Dry Sorbent Injection SO_2 Control Technology Review (RP982-47)	$99,100 7 months	Energy Technology Consultants, Inc./ *R. Rhudy*
State-of-the-Art Power Plant Project Technical Assistance (RP1403-40)	$70,000 5 months	SRI International/*G. Poe*
Demonstration of Improved Boiler Header (RP1403-47)	$160,000 12 months	Lower Colorado River Authority/*R. Viswanathan*
Evaluation of Westinghouse Solid-Oxide Fuel Cell Technology for Electric Utility Applications in Japan (RP1676-13)	$999,700 24 months	Westinghouse Electric Corp./*D. Rastler*
Fluidized-Bed Combustion of Alternative Fuels: Pilot and Commercial Plant Experience (RP2190-6)	$78,700 10 months	Combustion Systems, Inc./*C. McGowin*
Development of Zero-Discharge Wastewater Management System for Florida Power & Light's Martin Station IGCC Project (RP2221-25)	$248,648 8 months	Ch2M-Hill/*E. Clark*
Review of Concepts and Processes for High-Temperature Coal Gas Cleanup (RP2221-26)	$60,000 6 months	SRI International/*N. Hertz*
Superconducting Quantum Interference Device for Nondestructive Evaluation (RP2308-20)	$66,900 14 months	Island Hill Research/ *R. Nakata*
Proof-of-Concept Testing of an Integrated Dry Injection System for SO_x and NO_x Control (RP2533-14)	$150,000 18 months	Cottrell Environmental Sciences/*B. Toole-O'Neil*
Model Life Extension Program for Jointly Owned Coal-Fired Units (RP2596-12)	$60,000 12 months	Kansas Electric Utilities Research Program/ *S. Gehl*
High-Concentration Photovoltaic Technology Development (RP2703-2)	$288,300 11 months	Sunpower Corp./ *F. Goodman*
Advanced Digital Tuning and Maintenance Guidelines (RP2710-18)	$283,300 26 months	Integrated Systems, Inc./ *D. O'Connor*
Nuclear Power		
Reactor Pressure Vessel Embrittlement Technology Transfer (RP1757-83)	$99,800 11 months	Tenera LP/*T. Griesbach*
Modular High-Temperature Gas Reactor Evaluation (RP2079-25)	$60,000 7 months	Commonwealth Research Corp./*E. Rodwell*
Assessment of Size and Material Properties Effects on Reactor Vessel Integrity (RP2455-22)	$87,200 10 months	Novetech Corp./ *T. Griesbach*
High-Effectiveness Reflector/Shield for Reducing Damage Rate to PWR Pressure Vessels (RP2614-65)	$91,500 11 months	University of California, Berkeley/*T. Griesbach*
Passive Plant Natural Circulation BWR Core Studies (RP2660-57)	$550,000 12 months	General Electric Co./ *J. Yedidia*
Digital Control Self-Tuning Methods and Implementation Guidelines (RP2686-5)	$491,000 16 months	Westinghouse Electric Corp./*S. Bhatt*
Conversion of the Cobra-SFS Computer Program and Thermal-Hydraulic Analysis (RP2813-27)	$50,000 14 months	Battelle, Pacific Northwest Laboratories/*R. Williams*
Underwater Maintenance Guide (RP2814-24)	$61,000 7 months	J. M. Jenco & Associates, Inc./*M. Downs*
Best-Estimate LOCA Methodology for Four-Loop Plant and Application to Indian Point-2 (RP2956-3)	$251,500 25 months	Westinghouse Electric Corp./*P. Kalra*
Influence of Defect Kind and Size on Margins With Respect to Fast Fracture for Irradiated PWR Vessels (RP2975-17)	$50,000 5 months	Framatome/*T. Griesbach*
Automated Computerization of Plant Drawings (RP3045-1)	$443,800 9 months	GTX Corp./*R. Colley*
Survey and Characterization of Venturi Fouling (RP3097-1)	$114,100 10 months	Babcock & Wilcox Co./ *H. Ocken*
Reactor Internals Hydrogen Water Chemistry (RPC101-1)	$200,000 24 months	New York Power Authority/*R. Pathania*
Irradiation-Assisted Stress Corrosion Cracking (RPC101-6)	$402,000 36 months	Massachusetts Institute of Technology/*L. Nelson*
Influence of Irradiation and Stress/Strain on the In-Reactor Behavior of Various High-Purity Stainless Steels (RPC103-3)	$236,300 24 months	Siemens/*L. Nelson*
Utility Planning		
Utility Generation Fuel and Technology Screening (RP2767-5)	$77,700 7 months	Decision Focus, Inc./ *H. Mueller*
Sourcebook of Quality and Cost Management Methods and Tools (RP3026-3)	$750,000 13 months	CREASAP/*E. Altouney*

New Technical Reports

Requests for copies of reports should be directed to Research Reports Center, P.O. Box 50490, Palo Alto, California 94303; (415) 965-4081. There is no charge for reports requested by EPRI member utilities, U.S. universities, or government agencies. Reports will be provided to nonmember U.S. utilities only upon purchase of a license, the price for which will be equal to the price of EPRI membership. Others in the United States, Mexico, and Canada pay the listed price. Overseas price is double the listed price. Research Reports Center will send a catalog of EPRI reports on request. To order one-page summaries of reports, call the EPRI Hotline, (415) 855-2411.

CUSTOMER SYSTEMS

Residential Customer Preference and Behavior: CLASSIFY™ and PULSE® Technical Guide
EM-5907 Final Report (RP2671-1); $100
Contractors: National Analysts; Synergic Resources Corp.; QEI, Inc.
EPRI Project Manager: L. Lewis

Residential Customer Preference and Behavior: Effective Residential Program Design With PULSE®
EM-5909 Final Report (RP2671-1); $100
Contractors: National Analysts; Synergic Resources Corp.; QEI, Inc.
EPRI Project Manager: L. Lewis

Home Automation: What's in It for Utilities?
CU-6706 Final Report (RP2830-7); $25
Contractor: Levy Associates
EPRI Project Managers: L. Carmichael, V. Rabl, A. Lannus

Scanning the External Marketing Environment
CU-6728 Special Report; $100
EPRI Project Managers: C. Gellings, T. Yau

A Proposed Methodology for Rating Integrated Air-Source Heat Pumps
CU-6813 Final Report (RP2033-26); $100
Contractor: National Institute of Standards and Technology
EPRI Project Manager: J. Kesselring

Proceedings: Demand-Side Management Incentive Regulation
CU-6840 Proceedings (RP2982-2); $295
Contractor: Barakat & Chamberlin, Inc.
EPRI Project Managers: W. LeBlanc, P. Hanser

ELECTRICAL SYSTEMS

Substation Control and Protection Project
EL-6756 Final Report (RP1359-7); $62.50
Contractor: ABB
EPRI Project Managers: S. Nilsson, L. Mankoff

Evaluation of Pipe-Type Cable Joint Restraint Systems
EL-6760 Final Report (RP7894-1); $25
Contractor: Pirelli Cable Corp.
EPRI Project Manager: J. Shimshock

Bubble Generation During Transformer Overload
EL-6761 Final Report (RP1289-3); $25
Contractor: ABB
EPRI Project Manager: G. Addis

Transmission and Distribution Automation Systems
EL-6762 Proceedings (RP1359-16); $70
Contractor: Electric Research and Management
EPRI Project Managers: L. Mankoff, S. Nilsson, T. Kendrew

Study of Improved Load Tap Changing for Transformers and Voltage Regulators
EL-6764 Final Report (RP2763-2); $32.50
Contractor: Cooper Industries, Inc.
EPRI Project Manager: S. Lindgren

Electromagnetic Transients Program (EMTP) Field Test Comparisons
EL-6768 Final Report (RP2149-5); $47.50
Contractor: General Electric Co.
EPRI Project Manager: R. Adapa

Three-Conductor Compressed-Gas Cable Field Demonstration, Vols. 1 and 2
EL-6771 Final Report (RP7840-2, -3); Vol. 1, $25; Vol. 2, $25
Contractors: Detroit Edison Co.; Westinghouse Electric Corp.
EPRI Project Manager: J. Shimshock

Cost-Benefit Analysis of Power System Reliability: Determination of Interruption Costs, Vols. 1–3
EL-6791 Final Report (RP2878-1); Vol. 1, $47.50; Vol. 2, $47.50; Vol. 3, $32.50
Contractor: RCG/Hagler, Bailly, Inc.
EPRI Project Managers: N. Balu, M. Lauby

1989 EPRI PCB Seminar
EL/GS/EN-6792 Proceedings (RP2028); $55
EPRI Project Managers: G. Addis, M. McLearn, V. Niemeyer

Demonstration of a Two-Phase Cooled Power Transformer
EL-6794 Final Report (RP1499-3); $25
Contractor: Consolidated Edison Co. of New York, Inc.
EPRI Project Manager: G. Addis

Knowledge-Based System for Direct Stability Analysis
EL-6796 Final Report (RP2944-3); $32.50
Contractor: McMaster University
EPRI Project Manager: G. Ben-Yaacov

GENERATION AND STORAGE

Development and Application of the Coal Quality Impact Model: CQIM™
GS-6393 Final Report (RP2256-2); $32.50
Contractor: Black & Veatch, Engineers-Architects
EPRI Project Manager: A. Mehta

Condition Assessment Guidelines for Fossil Fuel Power Plant Components
GS-6724 Topical Report (RP2596-10); $5000
Contractors: Failure Analysis Associates; Heat Exchanger Systems; General Physics Corp.; Daedalus Associates, Inc.; Stone and Webster Engineering Corp.
EPRI Project Manager: B. Dooley

Enhanced Liners for Attenuating Utility By-Product Liquors
GS-6798 Final Report (RP1457-2); $32.50
Contractor: Battelle, Pacific Northwest Laboratories
EPRI Project Manager: M. McLearn

The 20-MW TVA Atmospheric Fluidized-Bed Boiler
GS-6805 Final Report (RP1860-1); $40
Contractor: Tennessee Valley Authority
EPRI Project Manager: T. Boyd

Database for Hydrocarbon-Contaminated Site Remediation: Software and Manual
GS-6812 Final Report (RP2991-2); $400
Contractor: Mill Creek Co.
EPRI Project Managers: L. Atherton, C Kulik

NUCLEAR POWER

Guidelines for the Repair of Nuclear Power Plant Safety-Related Motors (NCIG-12)
NP-6407 Final Report (RPQ101-9); $47.50
Contractors: NUTECH; Strategic Technology and Resources
EPRI Project Manager: W. Bilanin

MIST Final Report, Vol. 10: RELAP/MOD2 MIST Analysis Comparison
NP-6480 Final Report (RP2399); $40
Contractor: B&W Nuclear Service Co.
EPRI Project Manager: J. Sursock

Belgian Approach to Steam Generator Tube Plugging for Primary Water Stress Corrosion Cracking
NP-6626-M Final Report (RPS404-14); $25
Contractor: Belgatom
EPRI Project Manager: A. McIlree

Procedure for Seismic Evaluation and Design of Small Bore Piping (NCIG-14)
NP-6628 Final Report (RPQ101-16, -17); $25
Contractors: Stevenson and Associates; EQE Engineering
EPRI Project Manager: W. Bilanin

Utility Industry Evaluation of the Modular High-Temperature Gas-Cooled Reactor
NP-6676 Final Report (RP2079); $32.50
EPRI Project Manager: E. Rodwell

A Compendium of Robotic Equipment Used in Hazardous Environments
NP-6697 Final Report (RP2519-1); $62.50
Contractor: J. A. Jones Applied Research Co.
EPRI Project Manager: F. Gelhaus

Simulator Requirements Manual
NP-6701 Final Report (RP3107-2); $32.50
Contractor: D. C. Roessner
EPRI Project Manager: J. Sursock

Primary Water Stress Corrosion Cracking: 1989 EPRI Remedial Measures Workshop
NP-6719-M Proceedings (RPS406-3); $25
Contractor: Dominion Engineering, Inc.
EPRI Project Manager: A. McIlree

Microstructure Etching and Carbon Analysis Techniques
NP-6720-M Final Report (RPS408-1); $25
Contractor: Dominion Engineering, Inc.
EPRI Project Manager: C. Shoemaker

Cobalt Reduction Guidelines
NP-6737 Special Report; $25
EPRI Project Manager: H. Ocken

1989 EPRI Alloy 690 Workshop
NP-6750-M Proceedings (RPS408-1); $32.50
Contractor: Dominion Engineering, Inc.
EPRI Project Manager: A. McIlree

Evaluation of Sampling Schemes for In-Service Inspection of Steam Generator Tubing
NP-6774 Final Report (RPS404-11); $32.50
Contractor: Battelle, Pacific Northwest Laboratories
EPRI Project Manager: C. Welty

Reduction of Critical Path Time for BWR Recirculation System Decontaminations
NP-6778 Final Report (RP1329-3); $25
Contractor: Niagara Technical Consultants
EPRI Project Manager: C. Wood

1989 EPRI Radwaste Workshop
NP-6808 Proceedings (RP2414-28); $32.50
EPRI Project Manager: P. Robinson

ASME Code, Section XI: 1987–1989 Revisions and Updates
NP-6810 Final Report (RP2057-7); $47.50
Contractor: Science Applications International Corp.
EPRI Project Manager: S. Liu

New Computer Software

The Electric Power Software Center (EPSC) provides a single distribution center for computer programs developed by EPRI. The programs are distributed under license to users. EPRI member utilities, in paying their membership fees, prepay all royalties. EPRI software is not available to nonmember U.S. utilities. No royalties are charged to nonutility public service organizations in the United States, including government agencies, universities, and other tax-exempt organizations. Industrial organizations are required to pay royalties. Basic support in installing the codes is available at no charge from EPSC; however, a consulting fee may be charged for extensive support.

For more information about EPSC and licensing arrangements, EPRI member utilities, government agencies, universities, and other tax-exempt organizations should contact the Electric Power Software Center, Power Computing Co , 1930 Hi Line Drive, Dallas, Texas 75207; (214) 655-8883. Industrial organizations should contact EPRI's Manager of Licensing, P.O. Box 10412, Palo Alto, California 94303; (415) 855-2866.

COMMEND: Commercial Sector End-Use Energy Demand Forecasting Model
Version 3.1 (IBM PC); EM-4487-CCMP
Contractor: Regional Economic Research
EPRI Project Manager: Steven Braithwait

CRCS: Coal Routing and Costing System
Version 1.0 (IBM PC)
Contractor: CACI, Inc.
EPRI Project Manager: Edward Altouney

DSManager: Demand-Side Management Analysis Software
Version 1.0B (IBM PC)
Contractor: Decision Focus, Inc.
EPRI Project Manager: Philip Hanser

EGEAS: Electric Generation Expansion Analysis System
Version 4.1 (IBM PC-OS/2); EL-2561
Contractors: Massachusetts Institute of Technology; Stone & Webster Engineering Corp.
EPRI Project Manager: Giora Ben-Yaacov

ETADS: EPRI Tower Analysis and Design System
Version 2.1 (VAX, IBM PC-OS/2); EL-6420-CCML
Contractor: Sverdrup & Parcel and Associates, Inc.
EPRI Project Manager: Paul Lyons

ETMSP: Extended Transient–Midterm Stability Package
Version 2.0 (IBM-XA, VAX); EL-2004-CCM
Contractor: Arizona Public Service Co.
EPRI Project Manager: Mark Lauby

CALENDAR

For additional information on the meetings listed below, please contact the person indicated.

SEPTEMBER

19–21
Conference: Effects of Coal Quality on Power Plants
St. Louis, Missouri
Contact: Arun Mehta, (415) 855-2895

24–26
Railroad, Pipeline, and Transmission Line Compatibility
Haslet, Texas
Contact: Jim Hall, (415) 855-2305

24–26
Seminar: Service Water Systems Reliability Improvement
Atlanta, Georgia
Contact: Norris Hirota, (415) 855-2084

25–27
Use of Less-Volatile Amines in PWR Secondary-Side Water Treatment
Tampa, Florida
Contact: Tom Passell, (415) 855-2070

26–28
Coal Cleaning Plant O&M
Homer City, Pennsylvania
Contact: Barbara Fyock, (412) 479-6015

27–28
Overhead Transmission Line Optimization: TLOPWT
Haslet, Texas
Contact: Dick Kennon, (415) 855-2311

OCTOBER

1–4
International Conference and Workshop: Transport and Mass Exchange Processes in Sand and Gravel Aquifers
Ottawa, Canada
Contact: David McIntosh, (415) 855-7918

1–5
Computer-Aided Control System Analysis
Birmingham, Alabama
Contact: Murthy Divakaruni, (415) 855-2409

2–4
Electric Motor Diagnostics
Toronto, Canada
Contact: Jim Edmonds or J C. White, (415) 855-2291

9–11
Noncombustion Waste
New Orleans, Louisiana
Contact: Mary McLearn, (415) 855-2487

10–11
Workshop: Feedwater Heater Maintenance Technology
Eddystone, Pennsylvania
Contact: John Tsou, (415) 855-2220

10–11
Workshop: Gas Turbine Procurement (EPRI members only)
Danvers, Massachusetts
Contact: Henry Schreiber, (415) 855-2505

15–17
Incipient Failure Detection: Predictive Maintenance for the 1990s
Philadelphia, Pennsylvania
Contact: Sam Haddad, (415) 855-2172, or John Scheibel, (415) 855-2850

16–18
Fuel Supply Seminar
Memphis, Tennessee
Contact: Howard Mueller, (415) 855-2745

17–19
AIRPOL/90 Seminar: Solving Corrosion Problems in Air Pollution Control Equipment
Louisville, Kentucky
Contact: Paul Radcliffe, (415) 855-2720

22–24
Optical Disks: Information Technology for the Power Industry
Washington, D.C.
Contact: Joe Judy, (415) 855-8936

23–24
Food Processing Industry Workshop
San Francisco, California
Contact: Ammi Amarnath, (415) 855-2548

30–November 2
Vibration Testing and Analysis
Eddystone, Pennsylvania
Contact: Sam Haddad, (415) 855-2172

31–November 1
1990 Fuel Oil Utilization Workshop
Washington, D.C.
Contact: William Rovesti, (415) 855-2519

NOVEMBER

1–2
T&D Cable Installation
St. Petersburg, Florida
Contact: Tom Rodenbaugh, (415) 855-2306

14–16
1990 Electric Utility Market Research Symposium
Atlanta, Georgia
Contact: Thom Henneberger, (415) 855-2885

27–29
Thermography
Eddystone, Pennsylvania
Contact: Gordon Allen, (415) 855-2219, or Mike Downs, (415) 855-7940

28–29
NSAC and Operational Reactor Safety Engineering and Review Group Workshop: Self-Assessment During Plant Shutdown
Seattle, Washington
Contact: Bill Reuland, (415) 855-2977

DECEMBER

3–5
Symposium: Macrofouling
Orlando, Florida
Contact: Norris Hirota, (415) 855-2084

4–6
Fossil Fuel Plant Cycling
Washington, D.C.
Contact: Maureen Barbeau, (415) 855-2127

5–7
Workshop: Applications of Chaos
San Francisco, California
Contact: Jong Kim, (415) 855-2671

5–7
Workshop: Terry Turbine Controls
Orlando, Florida
Contact: Bob Kannor (415) 855-2018

11–12
Diesel Generator Diagnostics
Eddystone, Pennsylvania
Contact: Sam Haddad, (415) 855-2172

12–14
Workshop: Fossil Fuel Plant Control and Automation
Phoenix, Arizona
Contact: Murthy Divakaruni, (415) 855-2409

MARCH 1991

1–2
Improved Coal-Fired Power Plants
San Francisco, California
Contact: James Valverde, (415) 855-7998

6–8
2d Symposium: End Use
New Orleans, Louisiana
Contact: Dave Rigney, (415) 855-2419

25–28
1991 Symposium: Stationary NO_x Control
Washington, D.C.
Contact: David Eskinazi, (415) 855-2918

Authors and Articles

Shaw

Williams

Lambert

Smith

Samotyj

Rauch

Balu

Curtice

Ben-Yaacov

The Hard Road to Nuclear Waste Disposal (page 4) was written by Taylor Moore, *Journal* senior feature writer, with principal technical guidance from three members of the High-Level Waste and Spent-Fuel Storage Program of EPRI's Nuclear Power Division.

Robert Shaw, senior program manager, has headed research in this area since 1989, when he returned from over a year's loan assignment with GPU Nuclear. Before that, he led the Low-Level Waste and Coolant Technology Program. Shaw joined EPRI in 1975 from Clarkson College of Technology in Potsdam, New York, where he taught chemical engineering.

Robert Williams, technical adviser, has worked in all aspects of the nuclear fuel cycle since joining EPRI in 1975. For five years beginning in 1982, he served as program manager for external fuel cycle R&D. Williams came to EPRI after 10 years with General Electric, where he held several engineering positions. He began his engineering career in the U.S. Navy.

Ray Lambert, technical specialist, has primary responsibility for managing spent-fuel storage projects. Before joining EPRI in 1982, he was with General Electric for 23 years, where he managed engineering and economic process and design studies. ■

Those Blinking Clocks (page 18) was written by Jon Cohen, science writer, and David Boutacoff, *Journal* feature writer, in cooperation with three EPRI research managers.

William M. Smith has headed the Power Electronics and Controls Program in the Customer Systems Division since January 1989. Before that, he managed research on demand-side planning. Smith came to EPRI in 1985 after eight years with Pacific Gas and Electric, ultimately as the supervisor of load management projects.

Marek Samotyj, a senior project manager in the Power Electronics and Controls Program, came to EPRI as a consultant in 1984 and joined the staff a year later. Before that, he was a research assistant for the Energy Modeling Forum at Stanford University for three years. Still earlier, he held several consulting positions in Poland, including one with the Commission on National Economic Reform.

Greg Rauch, a project manager in the Distribution Program of EPRI's Electrical Systems Division, oversees research on magnetic fields and power quality. He came to EPRI in 1988 following 11 years with General Electric, where he worked successively in utility systems application engineering and international marketing. ■

Enhancing Power System Security (page 24) was written by Ralph Pred, science writer, who drew background material from two research managers in the Power System Planning and Operations Program of EPRI's Electrical Systems Division.

Neal Balu has managed the program since early 1988. He came to EPRI as a project manager in 1979 after seven years at Southern Company Services, where he headed the system planning department's system dynamics section. Earlier, he spent four years on the faculty of the Indian Institute of Technology in Bombay.

David Curtice, a project manager with a special interest in system operations, joined EPRI in August 1987. Before that, he worked for 11 years at Systems Control, where he was involved in the development of energy management systems and application software. ■

Advanced Workstation: One-Stop Software (page 32) was written by Steve Hoffman, consultant, with technical guidance from **Giora Ben-Yaacov** of EPRI's Electrical Systems Division.

Ben-Yaacov has managed software development for his division since he came to EPRI in 1981. His fields of application are computer modeling and analytical methods for the planning, design, and operation of power systems. Ben-Yaacov joined EPRI after working briefly as a senior consultant with Systems Control. He had previously been an engineer for 10 years with the Electricity Supply Commission in Johannesburg, South Africa. Still earlier, he was with the Atomic Energy Board in Israel. ■

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