Nurturing Clean Coal Technology

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Cover: Careful cultivation and new seed money from the Department of Energy are moving a number of clean coal-based power technologies toward successful demonstration.

EDITORIAL

Cooperative Development of Clean Coal Technology

After several years of relative calm, a new and considerably more complex debate has arisen over what to do about emissions from coal-fired power plants. Instead of focusing narrowly on sulfur dioxide as a precursor of acid rain, environmental concern has recently shifted toward a much broader agenda of issues. Emissions of nitrogen oxides (NO_x), unlike those of SO_2, have been on a rising trend and are implicated in urban ozone formation as well as acid rain. Growing concern about climatic warming and stratospheric ozone depletion brings carbon dioxide and nitrous oxide into the picture.

Although the contribution of coal combustion to these environmental concerns varies considerably—motor vehicles, for example, produce more NO_x emissions than do power plants—electric utilities may continue to be heavily affected by any new legislation. Faced with this political reality, the utility industry and EPRI took the lead in developing and demonstrating clean coal technologies that promise more cost-effective ways to reduce emissions. This has now evolved into a major R&D effort featuring a strong component of government-industry cooperation, with the U.S. Department of Energy cofunding its Clean Coal Technology Demonstration Program in cooperation with technology suppliers, utilities, and other coal users. EPRI is actively participating in this program by demonstrating a range of new technologies for retrofit, repowering, and new plant applications.

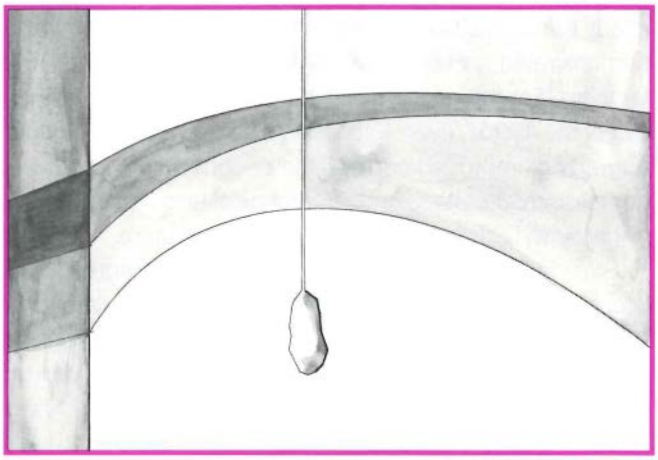
This month's cover story surveys both the policy considerations and technological issues associated with the current national efforts to find long-term solutions to coal's environmental problems. For these efforts to succeed, a broad menu of both repowering and retrofit emission control technologies must be demonstrated and deployed to the point where utilities and other coal users can confidently place orders for them. For the majority of these technologies, this stage is not expected to be reached until the second half of the 1990s, even with today's accelerated R&D effort. All categories of clean coal technology—fuel upgrading, improved combustion or conversion, and flue gas treatment—will eventually compete in the domestic marketplace on their technical and economic merits, and all have the potential to contribute significantly to U.S. technology exports in the future.

This expanded program of government-industry cooperation needs to be supported by a regulatory policy that takes into account the fact that, although the development effort is accelerating, there are inevitable lead times involved in bringing the technologies to commercial deployment. A carefully crafted regulatory policy that nurtures the development of clean coal technologies in this way will sustain the nation's already substantial progress in pollution control, yielding real and lasting reductions of emissions from coal use well into the 21st century.

Ian Torrens

Ian Torrens, Director
Environmental Control Systems Department
Generation and Storage Division

RESEARCH UPDATE



DEPARTMENTS

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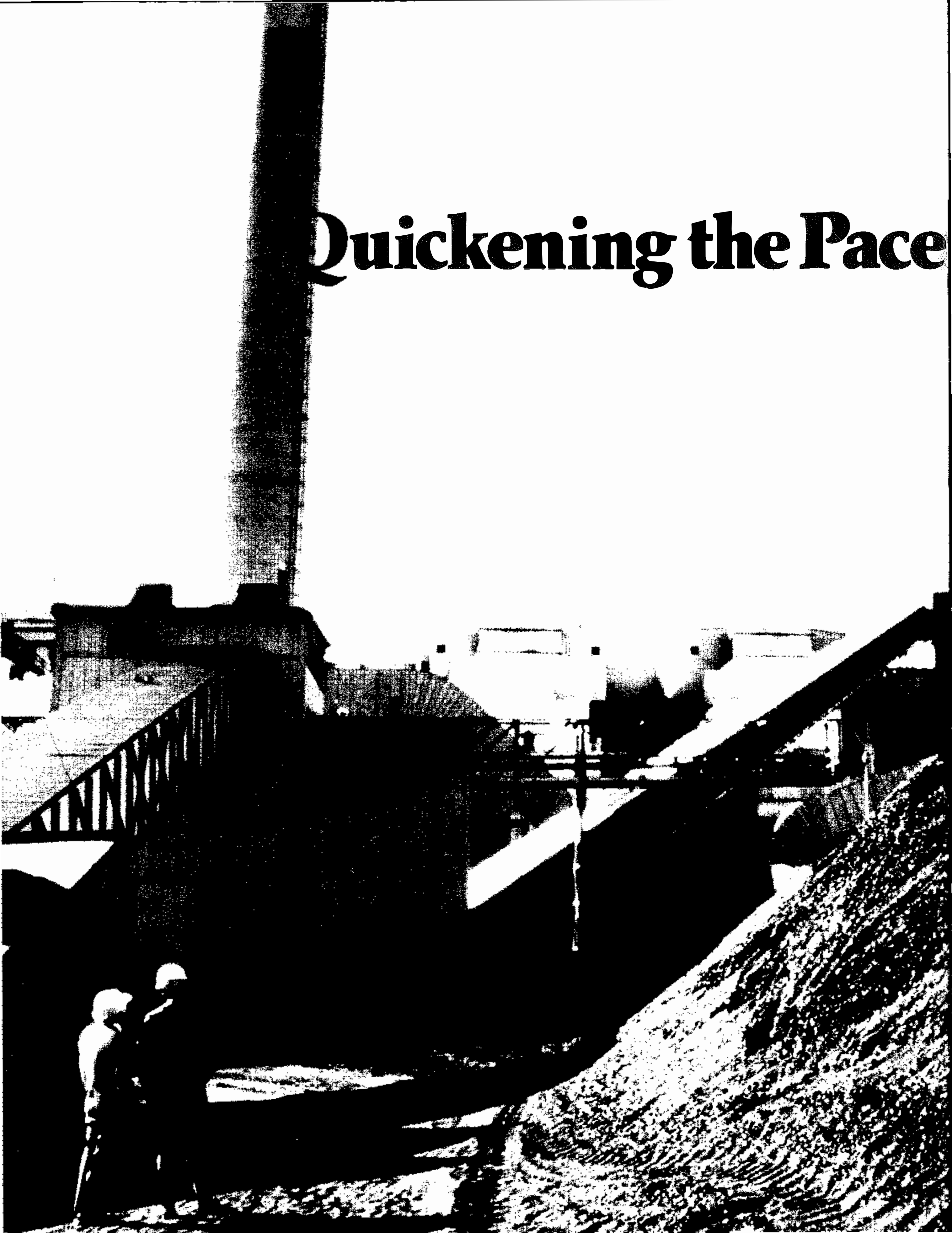
Quickening the Pace



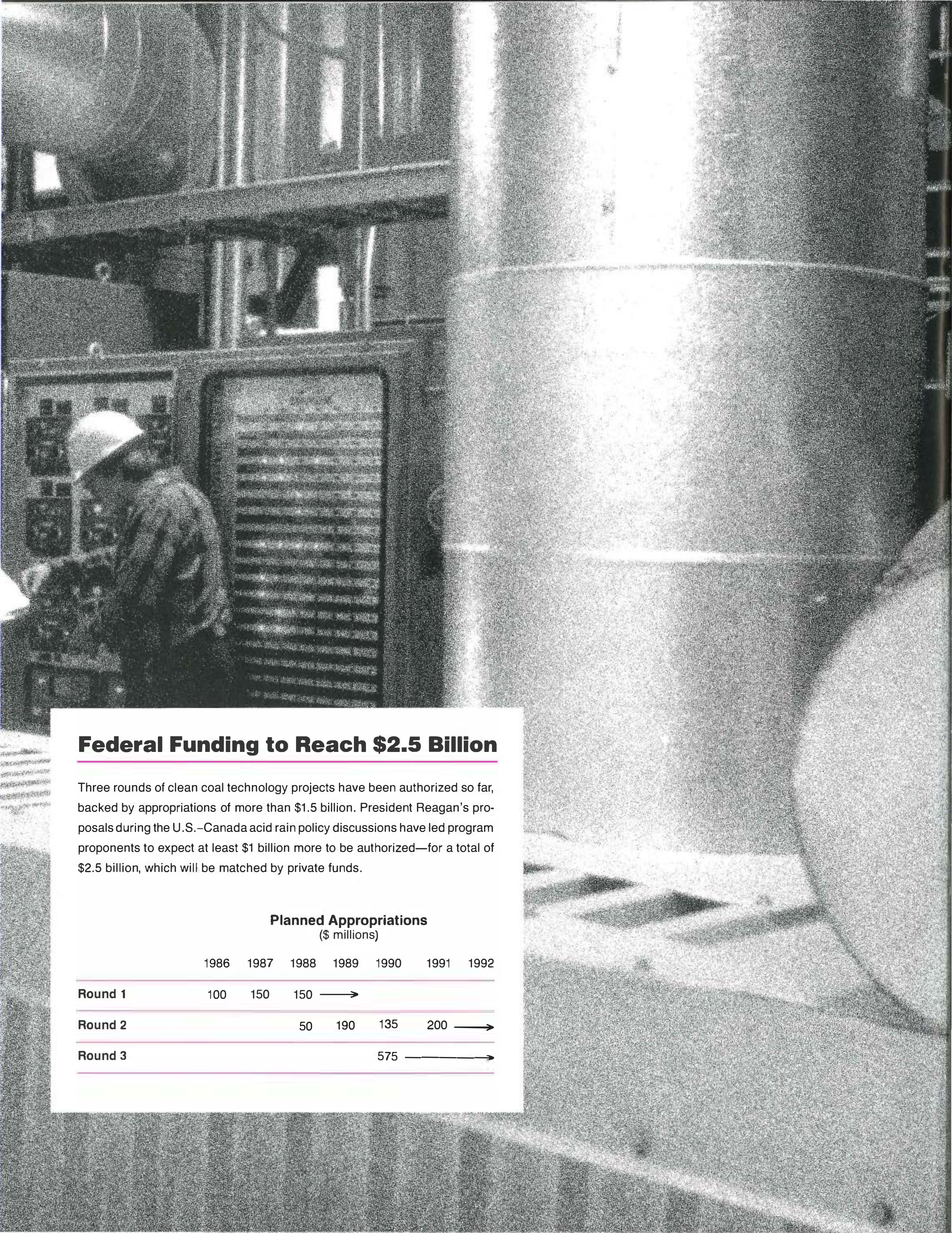
A second round of DOE cofunding will give a powerful boost to the timely development and demonstration of cost-effective clean coal technologies.

in Clean Coal Technology

The need for inherently cleaner, more efficient ways to burn coal is growing rapidly. Sometime during the first decade of the next century, coal is expected to surpass petroleum as the world's most utilized fuel. Between now and the middle of the next century, global coal production is expected to triple, and international trade in steam coal to rise 10- to 15-fold. Such explosive growth places coal on a collision course with renewed concern over the effects of coal plant emissions and brings fresh urgency to the search for clean coal technologies that could help resolve the historical conflict between environmental protection and economic expansion.

These technologies also represent an important opportunity to strengthen America's position in international trade during the early 21st century. Major coal reserves lie in regions whose growth and economic development could offer a substantial early market for imported clean coal equipment—including China, eastern Europe, southern Asia, and Africa. Already vigorous competition to commercialize advanced coal technologies has spread among some western European countries and Japan, as well as the United States.

So-called clean coal technologies are designed to achieve superior environmental protection at lower cost by combining sophisticated coal preparation, combustion, and conversion processes with improved postcombustion cleanup and state-of-the-art electronic instrumentation and controls. Several of these



Federal Funding to Reach $2.5 Billion

Three rounds of clean coal technology projects have been authorized so far, backed by appropriations of more than $1.5 billion. President Reagan's proposals during the U.S.–Canada acid rain policy discussions have led program proponents to expect at least $1 billion more to be authorized—for a total of $2.5 billion, which will be matched by private funds.

Planned Appropriations
($ millions)

	1986	1987	1988	1989	1990	1991	1992
Round 1	100	150	150	→			
Round 2			50	190	135	200	→
Round 3					575	→	→

technologies have already entered the large-scale demonstration phase of development and could be ready for commercial deployment by the mid-1990s. Reaching that goal, however, will require a sustained commitment to build further demonstration facilities necessary to resolve the remaining technical and economic issues facing each of the technologies.

A major step to accelerate the pace of commercialization was taken recently, as the U.S. Department of Energy (DOE) began providing substantial cost sharing for privately initiated projects in a collaborative clean coal technology demonstration program. This program represents a precedent-setting joint venture, in which public and private resources are combined to provide risk capital on a scale that would not otherwise be possible for the tightly regulated utility industry.

"Clean coal technologies will give utilities greater flexibility in responding to environmental constraints," says Ian Torrens, director of EPRI's Environmental Control Systems Department. "Commercialization of such technologies must proceed swiftly, however, if they are to be confidently considered as retrofit or repowering candidates in the current debate over emissions reduction, or to be available for an expected new round of plant orders in the mid-1990s. We look on the DOE program as a fine example of government-industry cooperation for a cleaner environment. It will help accelerate the deployment process and fulfill the promise of clean coal technologies earlier than could otherwise be achieved."

Window of opportunity

The mid-1990s loom ahead as a period of particular challenge for utilities. By that time, more than half of all existing coal-fired boilers will be 25 years old or older, and the demand for power is expected to reach or exceed available generating capacity. According to the North American Electric Reliability Council, the crossover of supply and demand curves would occur on a national basis in 1997 for a 2% annual demand growth or in 1993 for a 3% growth. Since 1982, demand growth has averaged 3.2% nationally, but in the past two years it has exceeded 4%, and particular regions with more rapid growth rates are already beginning to feel the strain.

Much of this heightened baseload demand will have to be met by adding new coal-fired generating capacity, while older coal plants may need to be refurbished for extended life and cleaner operation. For the moment, however, few baseload power plants of any kind are being built, and this hiatus in construction provides a narrow window of opportunity for commercializing clean coal technologies.

The basic attraction of coal remains its low cost and great abundance. Coal-fired power plants currently account for more than one-half of the electricity generated in the United States. In terms of price per Btu upon delivery to a utility, coal remains the least expensive fossil fuel, and its cost advantage is likely to grow even more substantial as oil and gas reserves are steadily depleted. DOE expects coal use to increase by 47% between 1986 and 2010.

The biggest obstacle to expansion of coal-fired power generation is the cost of environmental protection, which escalated rapidly during the 1970s and early 1980s. As much as 40% of the capital cost and 35% of the operating cost of new plants can be accounted for by their pollution control systems, which may also extract an energy penalty amounting to 3–8% of a plant's output. The effect of the Clean Air Act of 1970, together with subsequent amendments and regulatory interpretations, has been to impose the use of the most costly of these pollution control systems—flue gas desulfurization (FGD) equipment, known as scrubbers—on all new coal-fired power plants.

Part of the problem was that early introduction of FGD represented technology forcing—massive deployment of equipment before it had been optimized for reliability and economic performance. More than 50,000 MW of generating capacity have been involved, at a cost to date of more than $20 billion (in 1988 dollars). The same emissions reduction could have been accomplished at a substantially lower cost if more time and money had been spent initially to optimize the FGD technology. Part of the motivation behind the current national clean coal technology demonstration program is to avoid the sort of legislative technology forcing that has proved so expensive in the past.

Birth of a program

Over the past decade, private industry has spent more than $1 billion to bring clean coal technologies to the stage of demonstration prototypes. In the utility sector, EPRI has provided 15 years of commitment and leadership for the R&D effort on clean coal. Considerably greater expense, however, will be required to deploy these technologies in fully commercial plants.

Recognizing this problem, as well as the fact that little fundamental change had occurred in coal plant technology for nearly three decades, a coalition of coal producers, users, and equipment manufacturers formally proposed, in 1983, that the federal government join with industry in a collaborative effort to accelerate commercial demonstration of advanced technologies. Among other improvements, these technologies promised to reduce emissions more cost-effectively than conventional technologies existing at the time, with less wasted energy.

During the following two years, as political concern over acid rain began to grow, Congress created a federal clean coal program and provided $400 million for an initial round of joint projects—now known as Clean Coal Technology-1 (CCT-1)—to begin in 1986.

The international importance of the federal clean coal program became evident during U.S.-Canada discussions on the acid rain question. A joint report in 1986 by special envoys Drew Lewis of the United States and William Davis of Canada, who had been appointed to work out a compromise on the sensitive issue, recommended that the United States undertake a five-year, $5 billion program to demonstrate innovative emission control technology. President Reagan formally endorsed this proposal and announced plans to seek $2.5 billion for DOE's ongoing clean coal technology demonstration program—with matching funds to come from the private sector. That endorsement reflected a fundamental change in administration energy policy and made possible bipartisan support for the program.

The president also announced that his Task Force on Regulatory Relief would examine existing federal incentives and disincentives to the commercial deployment of clean coal technologies and that an Innovative Control Technology Advisory Panel (ICTAP) would be appointed to help DOE define criteria for project selection. (EPRI president Richard Balzhiser is chairman of the ICTAP working group charged with reviewing the status of various clean coal technologies.)

Critical control policy decisions

Although Congress has now approved $575 million for a full second round of joint projects (CCT-2) and another $575 million to start a third round (CCT-3), a major policy dispute that could have a serious impact on commercial deployment of clean coal technologies remains unresolved. Some congressional factions, which favor immediate action to curb acid rain while protecting the market for high-sulfur coal, have introduced bills that would mandate retrofitting many existing coal plants with today's commercially available FGD systems rather than waiting for improved coal technologies to become ready for widespread adoption. Other factions favor delaying new emissions requirements, in order to achieve the cost and energy savings potential of technological advances and provide greater assurance of sustained environmental improvement.

A forced investment in current technology could well set back commercial deployment of the more desirable alternatives. Quite apart from the U.S. scrubber experience of the 1970s, the brute-force approach to curbing acid rain has already been tried in West Germany, where strict emissions standards were imposed in 1984. Under this plan, individual plants were essentially forced to retrofit existing control technology in order to meet short deadlines for emissions reductions. Largely as a result, an active clean coal technology development program was nipped in the bud.

In the United States, an immediate requirement to retrofit currently available FGD might initially reduce emissions faster than waiting for demonstration of clean coal technologies. Over the longer term, however, advanced technologies have the potential to achieve and sustain substantially lower emissions at a reduced price, and to maintain U.S. leadership in the global coal technology market.

The National Coal Council estimates that advanced technologies could potentially be incorporated into some 170 GW of new or repowered coal plants and retrofitted into 140 GW of existing plants in the United States over the next 20 years. By the year 2010, the potential savings that would result from deploying clean coal technologies as they become available, rather than forcing adoption of current technology, could be more than $5 billion per year.

"The clean coal technology program is caught in a congressional tug-of-war, and critical decisions have to be made soon," says Kurt Yeager, vice president and director of EPRI's Generation and Storage Division. "Advanced technologies now under development make possible a more holistic approach to environmental protection, which addresses not only acid rain but the ozone, solid waste, and global warming issues as well. Clean coal technologies will use less water, produce lower quantities of waste products and more reusable byproducts, and—through their greater efficiency—contribute less carbon dioxide to the atmosphere, relative to current commercial practice. By contrast, the disincentives to R&D on clean coal technologies that would inevitably ensue from some congressional proposals will result over the long term in more environmental loading of the very pollutants they are designed to curb."

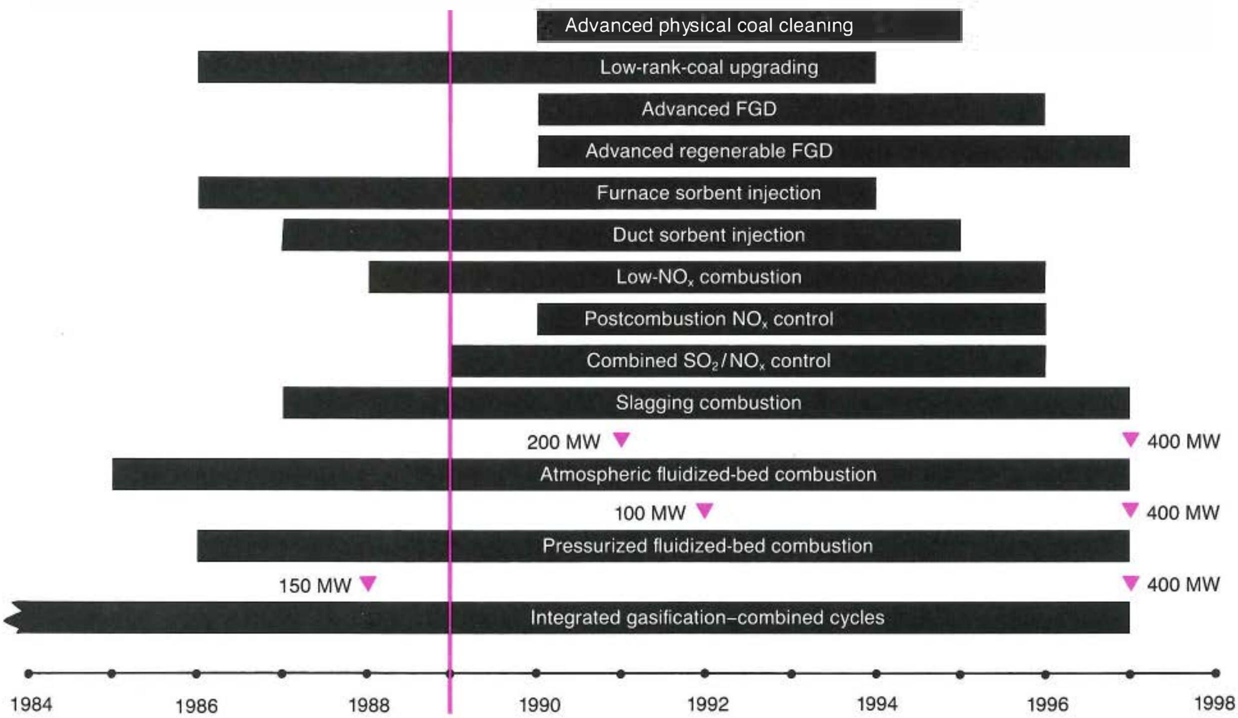
Building confidence

The first commercial unit of any technology is usually considerably more expensive than, say, the fifth or tenth unit—by an amount known as risk cost, the expense necessary to ensure reliable performance. The underlying purpose of the joint federal-private clean coal technology demonstration program is to build on the private sector's effort, share the risk cost, and accelerate the pace of commercial deployment.

Demonstration projects are designed to provide enough experience with a new technology under various circumstances to work out major technical bugs, resolve outstanding economic and environmental issues, and build confidence among potential buyers. In the case of clean coal technologies, approximately 65–85 demonstration projects are expected to be required to ensure confident commercialization over a variety of market conditions for the range of technological options necessary to satisfy utility needs. So far, 53 demonstration projects are planned or operating—including both ongoing private efforts and those cofunded by DOE under

Commercial Availability Targeted for Mid-1990s

The early 1990s are a window in time for proving out clean coal technologies that can be designed into the next generation of utility power plants. Demonstration plants in eight technology categories are already on order, and with orders in five more categories planned for 1989 and 1990, at least a dozen technology options should be ready for confident commercial order placement well before the turn of the century.



CCT-1 and CCT-2.

CCT-1 generally emphasized plant modifications for emissions control and advanced combustion projects for repowering. Such repowering involves substantial modification of an older plant, usually increasing its output and extending its life expectancy. Utility response to DOE's solicitation for CCT-1 was limited, however, because of strict conditions for recovering costs and revealing proprietary information.

The main emphasis of CCT-2 was on emission control technologies suitable for retrofitting—the installation of specific pieces of equipment in existing plants without having to substantially rebuild them. This emphasis reflects growing concern over potential retrofit requirements that may emerge in new acid rain or clean air legislation. Thirteen of the 16 CCT-2 projects selected by DOE are cosponsored by utilities. EPRI funding is involved in 8 of them.

"DOE's emphasis on retrofit technologies in its second solicitation shows that it recognizes the need to provide a broad menu of more cost-effective ways to combat acid rain, as well as other atmospheric problems," says Ian Torrens. "EPRI is committing $17 million to projects selected under Clean Coal-2, out of $284 million total cost, thus providing considerable leverage for our members' investment. Our participation will also help ensure objective evaluation and more effective dissemination of project results throughout the utility industry."

If these demonstration efforts prove successful, three major groups of clean coal technologies should become commercially available by the mid-1990s: fuel upgrading, SO_2 and NO_x emissions control, and advanced combustion and conversion.

Fuel upgrading

Precombustion coal treatment includes an important group of technologies that both improve the general quality of the fuel and remove some of the sulfur. These have significant potential for lowering the costs of SO_2 emission reduction when used in conjunction with other, lower-cost control technologies applied during or after combustion. Probably because of the retrofit emphasis, the CCT-2 selection did not include any utility fuel-upgrading projects. Several promising opportunities for demonstration remain in this area, however, and the clean coal initiative will be encouraged to include them in later rounds.

Technologies for upgrading fuel include physical and chemical coal cleaning, liquefaction, and processes that upgrade lower ranks of coal. Since 1981, much of the nation's development and demonstration work related to coal cleaning has taken place at EPRI's Coal Quality Development Center. This not only has accelerated new coal-cleaning technology but also has characterized cleanability costs and benefits for the variety of U.S. seam coals used by the utility industry, leading to both environmental and productivity improvements in power generation.

Emissions control

Technologies related to SO_2 and NO_x emissions control are being improved by a trend toward system simplification and better control of process chemistry. This trend is pointing the way toward reduced cost and improved integration of what was once "the box on the back end" with the rest of the plant. Most of these advanced control systems can be used as either retrofits or original equipment. EPRI's High-Sulfur Test Center now provides the focus for much of the pioneering development work in this field.

In the most common retrofit technology for SO_2 control, FGD, flue gases are exposed to an alkaline slurry that reacts with and removes more than 90% of the sulfur. In the 1970s, such equipment required up to 1000 gallons of water per minute in a 1000-MW plant and produced enough sludge each year to cover a square mile one foot deep. More recently, improvements to FGD combine much higher reliability with lower cost and lower water requirements than conventional units, and produce marketable waste products, such as wallboard-grade gypsum, instead of sludge.

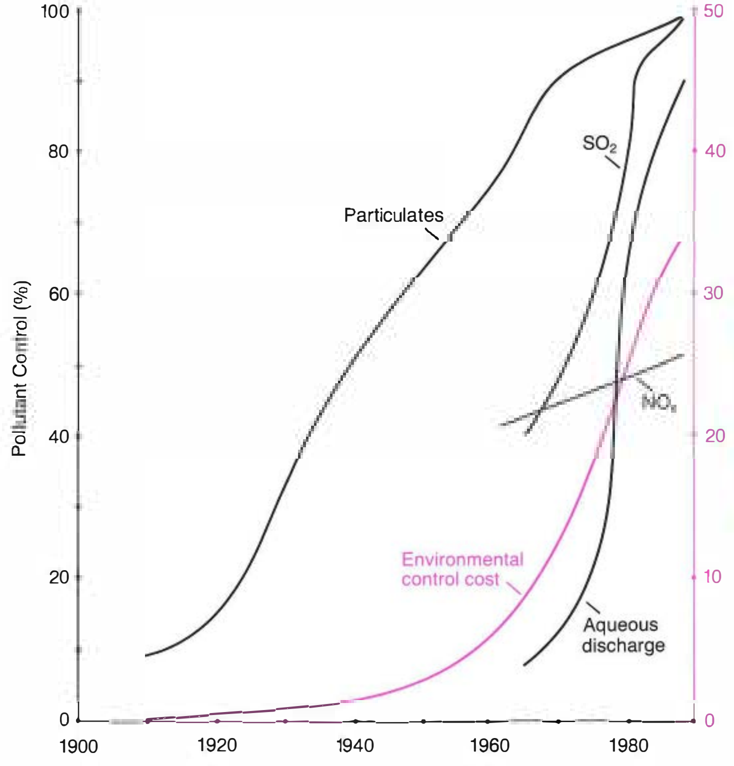
One innovative FGD system, which EPRI will test as part of CCT-2, is the Chiyoda Thoroughbred (CT-121) process. In this process, the conventional approach (bringing slurry into contact with flue gas by means of spraying) is replaced by a reactor in which the flue gas is bubbled through an alkaline liquid. EPRI will cooperate with Southern Company Services in a 100-MW demonstration of this technology on high-sulfur (2.5%) coal at Georgia Power's Yates plant in Florida. With a number of refinements in the reactor vessel and gypsum systems, this demonstration is expected to result in high SO_2 removal (90–95%) and benign wastes, at a substantially reduced cost.

In addition to the CT-121 demonstration, two other wet-FGD projects were selected for CCT-2 funding. The Passamaquoddy Tribe of Maine will demonstrate a recovery scrubber, which uses a waste product—cement dust or biomass ash—as a scrubbing agent and produces two salable by-products, potassium sulfate fertilizer and distilled water. This type of process may be potentially useful in utility applications where similar waste products are locally available. An innovative single-loop FGD, which eliminates the need for an external oxidation unit and handles the flue gas from several boilers, will be demonstrated by Pure Air Co. and Northern Indiana Public Service Co.

One way to reduce the need for water in an FGD system is through dry scrubbing, a process that uses a slurry (such as calcium hydroxide) that dries as it reacts with SO_2. The dry product is then

The Rising Cost of Environmental Controls

Technology has produced ever better systems for abating power plant emissions, but at ever higher cost. Removal of fly ash, or soot, began early in the century; control of chemical emissions has been a major focus since the 1960s. Pollution controls, including solid-waste management, represent at least one-third of the total cost of recently built coal-fired plants.



captured in a fabric filter or electrostatic precipitator downstream. The Tennessee Valley Authority, Ontario Hydro, and EPRI are currently testing a 10-MW spray dryer–precipitator combination at TVA's Shawnee plant, while at the High-Sulfur Test Center a 4-MW spray dryer–fabric filter combination is showing good potential with high-sulfur coal.

An alternative dry method for removing moderate amounts (less than 70%) of sulfur from flue gases at lower capital cost and less process complexity than FGD is sorbent injection. In this process, calcium compounds are injected directly into either the furnace or the flue duct, where they react with sulfur to form solid materials that are removed from the gas stream along with other particulates.

Three technologies involving injection of a powder or slurry sorbent between the furnace and the particulate control device will be demonstrated under CCT-2 at the 180-MW Yorktown No. 2 unit of Virginia Power by Combustion Engineering.

Attention on NO_x

As concern has grown regarding the role of nitrogen oxides in acid rain formation, photochemical oxidant formation, and ozone layer depletion, new emphasis has been placed on control of NO_x emissions. By far the least expensive way to reduce such emissions from a power plant is through combustion modification. This approach involves the redesign of burners or the rearrangement of fuel-air flow through a furnace to reduce flame temperature and thus limit oxidation of nitrogen in the fuel. Single modifications typically reduce NO_x levels by 40–60%, although combinations of methods may achieve reductions up to 75%. Combustion modification technologies are now ready for demonstration on all four major categories of existing U.S. boilers.

Achieving higher levels of NO_x control (more than 80% removal) requires much more costly flue gas treatment to convert or remove NO_x after it leaves the furnace. Although a number of such postcombustion controls have been tried at small scale, only one—selective catalytic reduction (SCR), developed in Japan—has reached substantial commercial application. In the SCR process, ammonia is mixed with flue gas in the presence of a catalyst, reducing NO_x to molecular nitrogen and water. So far, all full-scale installations of SCR on coal plants have taken place abroad, mostly in Japan and West Germany, and have involved only low-sulfur coal (less than about 1.5%). SCR is currently estimated to be 5–10 times more costly than combustion modification for NO_x control. EPRI is leading U.S. efforts to evaluate the effectiveness of SCR, at pilot scale, on American coals with higher sulfur levels. A major point of concern is what deleterious effect SO_2-laden flue gas may have on catalyst life—an important component of the technology's cost.

Three low-NO_x combustion modification projects and one SCR prototype demonstration project are being funded under CCT-2, all with EPRI participation. Two low-NO_x burner retrofits and the SCR demonstration are being carried out by Southern Company Services on power plants in its area. The third combustion modification project involves Babcock & Wilcox coal reburning technology on a cyclone boiler in Wisconsin. Utilities are expected to be particularly interested in the economic data generated by these projects, which will document the cost differences between combustion modification and SCR under typical U.S. utility conditions.

Combinations of the technologies just described can also be used to control emissions of SO_2 and NO_x simultaneously. Two projects funded under CCT-1 sought to remove moderate amounts (50–60%) of both pollutants by combining sorbent injection with combustion modification. Two CCT-2 projects are aimed at considerably greater reduction levels. One uses catalytic reduction to remove both SO_2 and NO_x and produce commercial-grade sulfuric acid. This project, being carried out by Combustion Engineering at Ohio Edison's Niles station, will involve processing flue gas equivalent to about 35 MW of generation. The other project, a 5-MW demonstration by Babcock & Wilcox at Ohio Edison's R.E. Burger station, combines sorbent and ammonia injection with particulate removal in a high-temperature baghouse. EPRI is evaluating these projects for possible participation.

Retrofitting of emission control technologies is likely to be an important component of any future acid rain or clean air legislation. With the results of DOE's CCT-2 round of projects on hand, the utility industry will be better equipped to respond effectively to the requirements of such legislation.

Advanced combustion and gasification

Over the longer term, environmental protection can be achieved most efficiently by developing advanced combustion and gasification technologies that have built-in emissions control. Generally speaking, such technologies are designed for new or repowered plants, rather than for retrofitting. An additional advantage is that most of the plants based on these technologies can be built cost-effectively in relatively small units, thus making possible modular construction with short lead times.

Atmospheric fluidized-bed combustion (AFBC) combines pulverized coal with limestone particles in a hot bed that is fluidized by upflowing air. Calcium in the limestone combines with sulfur in the coal to reduce SO_2 emissions by about 90%. Low combustion temperatures (1450–1600°F) result in inherently reduced NO_x formation. Three major utility AFBC demonstrations based on repowering of existing plants are now in operation: TVA's 160-MW Shawnee plant, Northern States

Power's 130-MW Black Dog station, and Colorado Ute's 110-MW Nucla station. This family of privately supported demonstrations has provided an important prototype for the national clean coal technology initiative. EPRI-sponsored tests are expected to begin at all three plants in the near future, at the completion of their startup phase. In addition, CCT-1 contributed funds to the Nucla station project and CCT-2 has provided funds to repower a 250-MW unit at the Nichols station of Southwestern Public Service Co.

Pressurized fluidized-bed combustion (PFBC) is similar to AFBC but operates at approximately 10 atmospheres pressure. Two advantages of such operation include higher thermal efficiency and a smaller boiler, which can be shop-fabricated and transported to a plant site by barge or rail. High-pressure operation also produces hot gases from the combustor that can be used to drive a gas turbine directly, after particulates are removed. How to clean these hot gases, however, remains an important technical challenge for PFBC, which is just beginning to enter the commercial demonstration phase of development.

A leading center for recent development work on PFBC, with support from both EPRI and DOE, has been a 30-MW test facility in Grimethorpe, England. The world's first commercial PFBC is a 10-MW unit at the University of Aachen, in West Germany. CCT-1 includes funding for a 70-MW demonstration project at the deactivated Tidd plant of American Electric Power, near Brilliant, Ohio. AEP also received funds under CCT-2 to repower units of its Philip Sporn plant in New Haven, West Virginia, with a 330-MW PFBC facility.

An especially effective way to lower emissions while increasing overall plant efficiency is through integrated gasification-combined-cycle (IGCC) technology. In this approach, a clean-burning gas is created by reacting coal with oxygen (or air) and steam, then burned to drive a combustion turbine while raising steam with recaptured heat to drive a steam turbine. A particularly important advantage of IGCC is that capacity can be added in stages. Thus, when natural gas prices are low, a utility can just buy a combustion turbine and perhaps add a steam turbine in a combined cycle, as demand warrants. Later, if the price of natural gas rises, a coal gasification stage can be added.

During the past 10 years, a variety of advanced IGCC technologies have been developed. The world's first fully integrated, commercial-scale IGCC plant was the 100-MW Cool Water demonstration facility, built by an EPRI-led consortium. This facility has now successfully completed its five-year test program and is scheduled to be shut down in early 1989. On the basis of data from Cool Water, more than 10 utilities are now conducting or planning site-specific designs for IGCC power plants, most using a phased-construction approach. As part of the Clean Coal Demonstration Program, DOE is currently funding three IGCC demonstration projects that are considerably smaller than Cool Water and use alternative gasifier designs.

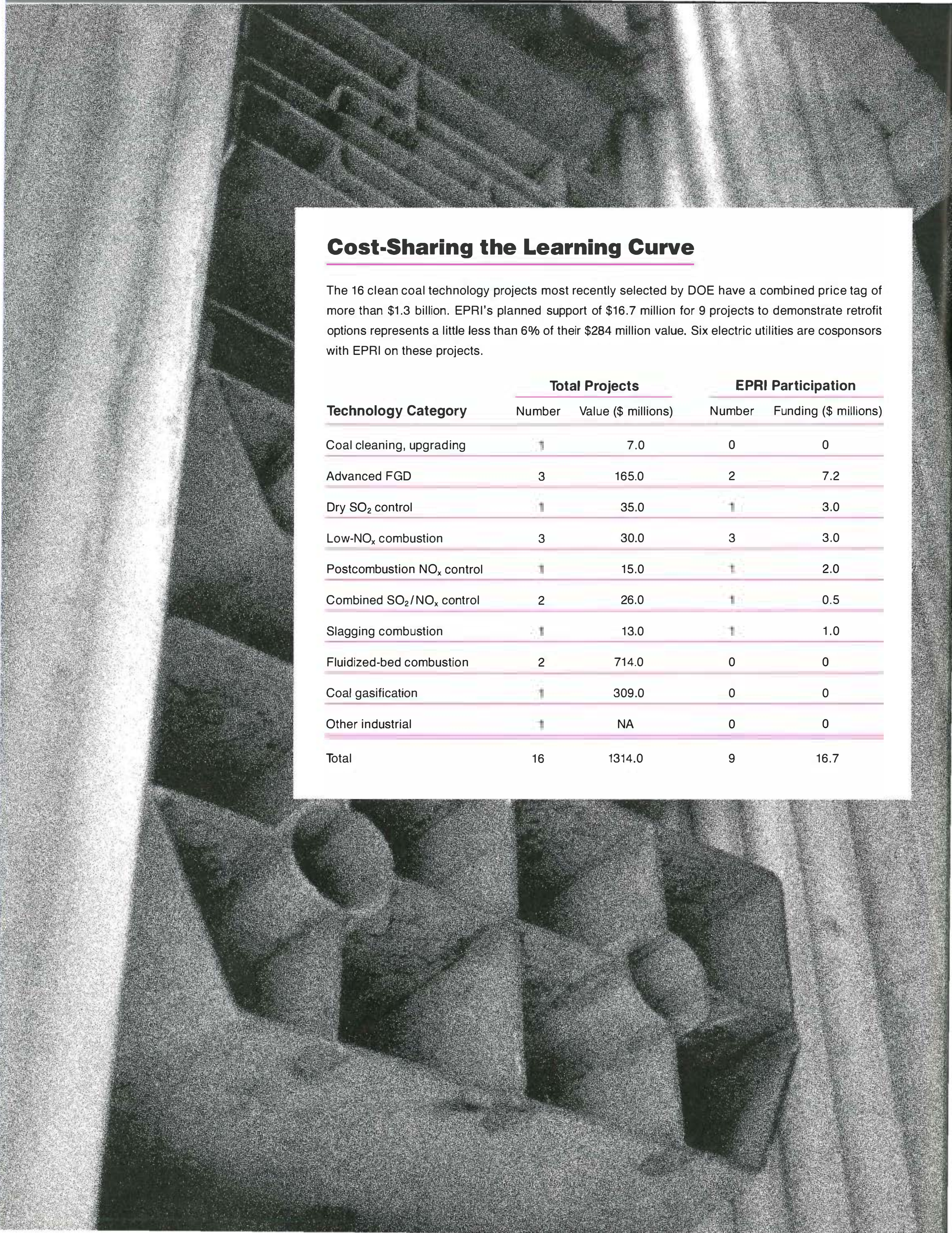
One technology in the advanced combustion group that is capable of retrofit is slagging combustion. Although its primary purpose is to convert oil-fired boilers to coal, the technology can also reduce emissions of both NO_x, by multistage combustion, and SO_2, via sorbent injection. Temperatures in the combustor are high enough to melt most of the coal ash so it can be removed as a molten slag. Following involvement with TRW (under the DOE CCT-1 funding round) in a 70-MW demonstration of a slagging combustor at Orange and Rockland's Lovett plant, EPRI will participate in a 33-MW demonstration of a different type of slagging combustor, by TransAlta, on a Southern Illinois Power Cooperative boiler.

"Advanced combustion technologies are clearly on the verge of commercialization for utility use," says Ron Wolk, director of EPRI's Advanced Fossil Power Systems Department. "The AFBC demonstrations now coming on-line will provide the critical operating and economic data utilities need before making investment decisions. PFBC development is moving ahead nicely under DOE's program. IGCC promises to be quite competitive once new coal-fired plants are ordered, but the timing of these orders will depend somewhat on oil and gas prices. Because of rising concern over the greenhouse effect and global warming, I expect that Clean Coal-3 may place more emphasis on plant efficiency. From that point of view IGCC looks particularly good, and we expect to propose larger-scale demonstration projects to DOE."

International market

In the final analysis, advanced coal technologies represent much more than a technical "fix" for environmental concerns and a cost-effective approach to domestic energy production. They also constitute a strategic capability for enhancing U.S. competitiveness in a rapidly expanding area of international trade: by the year 2000, the worldwide market for clean coal technology is expected to reach $50 billion per year.

The underlying reason for this dramatic upsurge is that coal is the most abundant and evenly distributed of the world's fossil fuels. Over the next two or three decades, coal is expected to account for one-half to two-thirds of the world's energy growth, largely through its dominant role in electricity generation. This expansion will further accelerate international markets both for the fuel itself and for advanced generation technologies. Developing nations, in particular, will need to buy equipment abroad for use in new power plants. A recent United Nations study predicted that some 110,000 MW of new coal-fired



Cost-Sharing the Learning Curve

The 16 clean coal technology projects most recently selected by DOE have a combined price tag of more than $1.3 billion. EPRI's planned support of $16.7 million for 9 projects to demonstrate retrofit options represents a little less than 6% of their $284 million value. Six electric utilities are cosponsors with EPRI on these projects.

	Total Projects		EPRI Participation	
Technology Category	Number	Value ($ millions)	Number	Funding ($ millions)
Coal cleaning, upgrading	1	7.0	0	0
Advanced FGD	3	165.0	2	7.2
Dry SO_2 control	1	35.0	1	3.0
Low-NO_x combustion	3	30.0	3	3.0
Postcombustion NO_x control	1	15.0	1	2.0
Combined SO_2/NO_x control	2	26.0	1	0.5
Slagging combustion	1	13.0	1	1.0
Fluidized-bed combustion	2	714.0	0	0
Coal gasification	1	309.0	0	0
Other industrial	1	NA	0	0
Total	16	1314.0	9	16.7

capacity will be built during the next 10 years in countries of the Asia-Pacific region alone.

In the past, developing countries have often imported power generation technologies that were well below the state of the art. Increasingly, because of acid rain, global warming, and other environmental problems, it may be in the best interest of all countries for the developing world to have access to more advanced clean coal technologies. Not only do new plants based on these technologies reduce the SO_2 and NO_x pollution associated with growth, they also could help raise the efficiency of fossil fuel generation in the developing world from the high 20s, in percentage points, to at least the high 30s—thus reducing the growth of carbon dioxide emissions as well.

America's role in this technological market will depend largely on how successful current efforts are in demonstrating clean coal technologies. Competition is likely to be fierce. According to the National Coal Council, Japan and Germany are expected to become primary suppliers of advanced scrubber technology in the 1990s, while virtually all retrofit NO_x technology is already being imported from Japan. The majority of AFBC plants in the United States now use technology from European nations, which are also the only commercial source of PFBC technology. The sole area in which the United States has a clear lead, the council concludes, is coal conversion. In addition, some newer technologies being developed under the DOE clean coal program—such as slagging combustion, combined SO_2/NO_x control, and advanced wet or dry FGD—could become prime candidates for U.S. technical leadership and show considerable export potential.

In addition to generating electricity, coal will also probably be used increasingly as a raw material for the production of transportation fuels and industrial feedstocks. For this conversion to be made economically, conventional coal plants are likely to give way to highly efficient baseloaded "coal refineries," in which a variety of generation and refining processes are integrated by using sophisticated electronic controls and diagnostic instrumentation. A coal gasifier and fluidized-bed boiler, for example, could be linked to gas turbines, fuel cells, and chemical processing units to produce inexpensive electricity, high-grade organic feedstocks, and marketable by-products ranging from elemental sulfur to valuable trace metals. Even carbon dioxide recovery could be included, both for commercial use and to reduce the contribution to the greenhouse effect.

"The United States can play a major role in the growing international market for new generating capacity by providing advanced technology—the 'smart parts'—for hundreds of new coal plants that will be needed over the next decades," says Kurt Yeager. "The clean coal technologies now being demonstrated are needed to provide essential building blocks for the integrated coal refineries of the future. The collaborative demonstration program currently focused on these technologies can help put the United States at the vanguard of international efforts to render the world's most abundant fossil fuel environmentally benign while keeping its economic competitiveness intact."

Target 2000

In addition to participating in numerous R&D projects related to specific clean coal technologies, EPRI's Generation and Storage Division has developed a broad profile of what coal-fired power plants will have to be like by the turn of the century. As part of a planning exercise called Target 2000, EPRI staff members and utility representatives on the division research advisory committees were asked to estimate the performance standards for future coal plants. The results of this survey are currently being incorporated into the division's budget and program proposals.

Among the characteristics considered desirable and achievable for baseload coal plants within the time provided are 85–90% availability, heat rate in the range of 8500–9000 Btu/kWh, a 50- to 60-year plant life, and a three-and-a-half-year construction time with reduced siting requirements. Utilities will also need plants that can handle a wider range of coals and that can be economical in smaller units, which can match changing demand more quickly and precisely.

"In order to meet these targets, we are emphasizing development of better control systems and instrumentation, together with advanced diagnostic monitoring and automation," says George Preston, director of the Fossil Power Plants Department. "With this equipment and other available technologies, I believe we can reduce O&M costs by 25%, lower capital costs by 20%, and eliminate forced outages. Such cost reductions, and the lower electricity rates they can create, are essential for keeping coal competitive in the years ahead."

Target 2000 coal plants will have to be environmentally cleaner, too. Ian Torrens agrees that cost reduction will be a prime objective, and adds: "Stricter environmental regulations seem inevitable. While we cannot anticipate what these will be with any degree of certainty, our R&D target is to position our members to meet possible environmental regulatory requirements for the final years of the century at a cost substantially below that of today's power plant environmental control. We will do this both by simplifying control technologies and by ensuring that they are better integrated with the rest of the power plant." ■

This article was written by science writer John Douglas from information provided by Kurt Yeager, Ian Torrens, Ronald Wolk, and George Preston of the Generation and Storage Division. Additional information was provided by Stephen Baruch, George Wiltsee, and Neville Holt.

Freeze Concentration:
An Energy-Efficient Separation Process

Evaporation processes have long been the technology of choice for extracting water from liquid mixtures. Now, especially with such consumables as milk, electric freeze concentration techniques may produce a higher-quality product at a lower cost.

The concentration and separation of materials from liquid solutions is a critical step in many industrial processes. Typically this step involves energy-intensive evaporation or distillation methods, which use heat to drive off gases from a liquid. Now, however, a new generation of freeze concentration technologies is creating opportunities to separate substances in crystalline form at substantial savings in cost and energy. Based on electric refrigeration, these technologies have a wide range of potential applications—from the preparation of food and chemicals to the treatment of wastewater.

The fundamental principles underlying freeze concentration have long been understood, and there have been some limited commercial applications since the 1950s. For example, about two-thirds of domestic high-purity p-xylene (used in the production of polyester) is now separated by freeze crystallization from a mixture of petrochemicals. A variety of recent developments in the technology have opened new opportunities to apply it much more widely, at a much larger scale.

An EPRI study conducted by Heist Engineering Corp. indicates that the substitution of freeze concentration technology for evaporation and distillation in all feasible cases would lead to annual savings of $5.5 billion for the industries involved, while increasing electric power consumption by 20 billion kWh per year. The study concluded that approximately 75% of this feasible changeover would actually be accomplished during the next 25 years. To hasten this conversion, EPRI has undertaken joint research projects with selected industry groups to demonstrate the commercial feasibility of freeze concentration in a variety of applications.

Opportunity for dairies

Dairies are the largest user of energy for product concentration in the food industry. Currently, steam-driven evaporators are used to process most concentrated and dry milk products. Many of these evaporators are quite old and inefficient. And even the newer models still have some significant disadvantages. To prevent the buildup of microorganisms that can grow at operating temperatures, an evaporator must be shut down every 20 hours or so for sanitizing. The condensed moisture from evaporators contains enough organic material to cause waste treatment problems. Product loss—generally equal to about 1% of total milk solids—represents a significant cost. Finally, exposure to heat in an evaporator denatures the proteins in milk and degrades its flavor.

Replacing a single 50,000-pound-per-hour evaporator with current-technology freeze concentration would result in savings of $100,000 per year through lower energy costs alone. Instead of oil or natural gas, the plant would consume about 7.4 million kWh of electricity annually. Moreover, freeze technology would give dairies an important opportunity to offer new and improved products.

Frozen concentrated milk, for example—similar in concept to frozen orange juice—could be introduced to a variety of markets. Such a product would have a long shelf life and could easily be reconstituted to produce fresh-tasting whole milk. Liquid condensed milk, with the consistency of today's evaporated milk, could also be produced by freeze concentration for use in cooking. In addition, the taste of powdered milk could be improved, and better use could be made of milk by-products.

The most important of these by-products is whey, the watery liquid that remains when cheese is curdled. Although whey contains useful proteins and lactose (milk sugar), most of it is now simply dumped—a smelly process involving settling tanks or open discharge onto the soil. Evaporation is generally too expensive for removing the excess water from whey and destroys many of its proteins. Freeze concentration, however, could be used to produce both pharmaceutical-grade lactose (which crystallizes eutectically out of the solution) and whey protein concentrate (which forms when the remaining condensed liquid is passed through a spray dryer). This concentrate has a higher protein content than either egg albumin or soybean curd and could become an important dietary supplement for both humans and livestock.

"Freeze concentration has great potential for expanding traditional dairy markets," says Ammi Amarnath, project manager in EPRI's Customer Systems Division. "A can of frozen concentrated milk product will keep for two months in the freezer and can then be reconstituted by simply mixing it with two cans of water. Although it's not on the market yet, I've tried samples and they tasted just like fresh milk, maybe even better. The taste of powdered product is also much improved. These developments can help dairies expand beyond their usual regional markets. The export potential is also great, because the United States currently has 20–30% excess production of milk, while many less developed countries have a severe shortage."

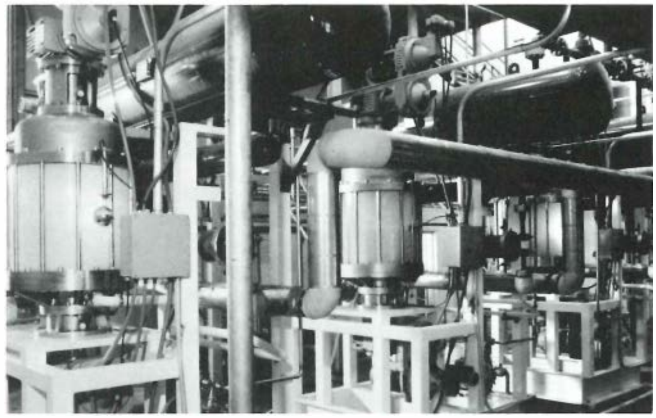
Pilot project

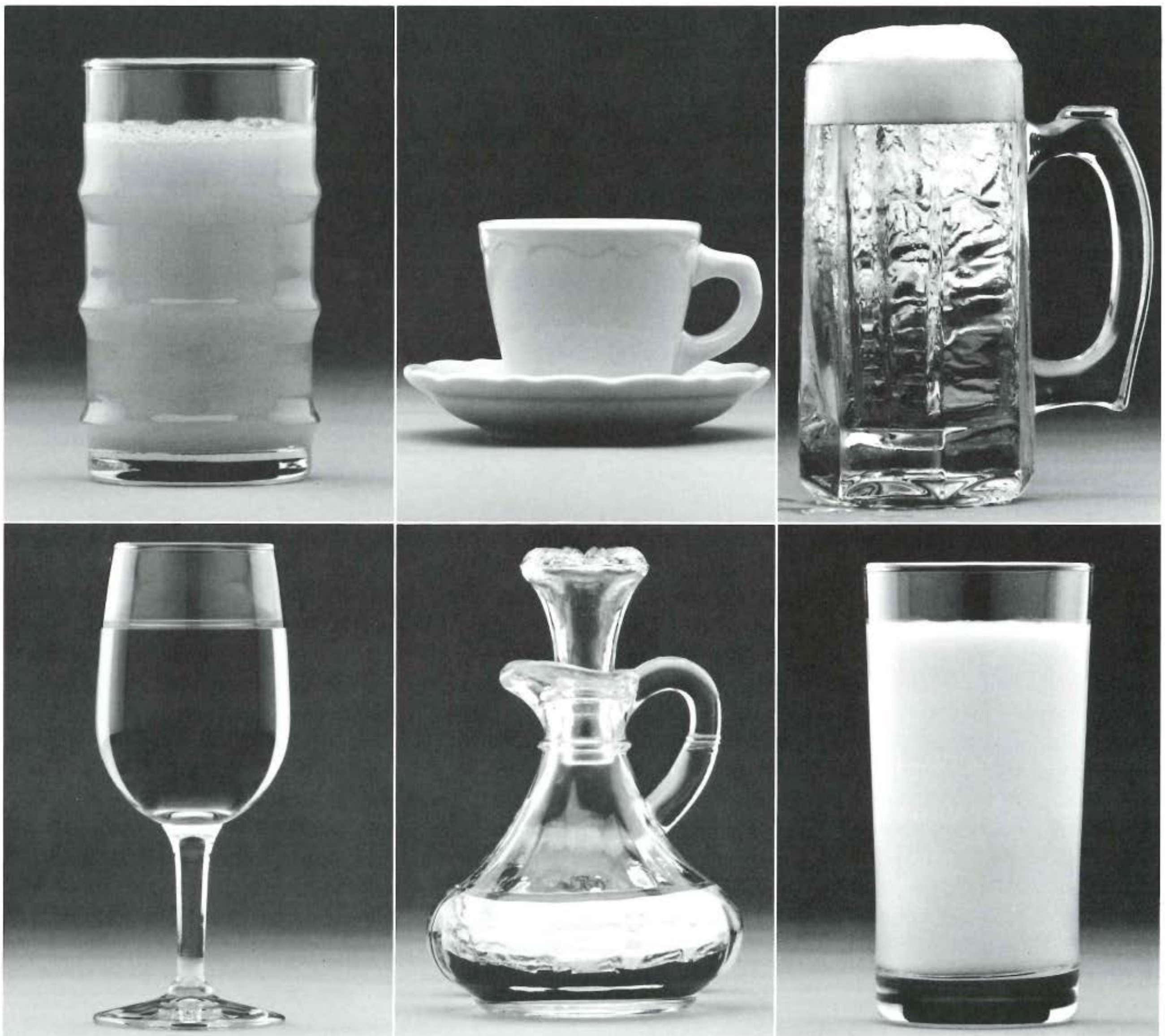
Responding to the promise of potential benefits for both the dairy and electric power industries, EPRI and Dairy Research, Inc. (DRINC), the research arm of the U.S. dairy industry, are conducting a joint project to determine the feasibility of using freeze concentration technology in the preparation of milk products. Phase 1 of this project, involving pilot-scale experiments, has just been completed. Phase 2, the demonstration of the technology in a working dairy, is expected to begin soon and to continue for two and a half years. The U.S. Department of Energy and Grenco Process Technology, a Dutch manufacturer of freeze concentration equipment, will be additional cosponsors of the phase 2 work.

During the pilot-scale tests, several factors that could affect the commercial feasibility of freeze concentration were con-

Freeze Concentration in the Food Industry

Freeze concentration separates water from food liquids without the loss of flavor or aroma characteristic of evaporation and distillation processes. Established commercial applications include fruit juices, coffee, beer, wine, and vinegar, and new opportunities are being pursued in the dairy industry. Frozen concentrated milk, powdered evaporated milk, and liquid condensed milk, for example, would have a long shelf life and could be marketed in areas where fresh milk is unavailable. The technology could also be used to process whey, a milk by-product, to produce pharmaceutical-grade lactose and whey protein concentrate.





Freeze Concentration Technology

Three major pieces of equipment are typically involved in the freeze concentration process. The first, of course, is a refrigeration unit, which cools a solution below the freezing point of one constituent. Depending on the composition of the solution and the pressure applied, either the solvent (e.g., water) or a dissolved solute (e.g., salt) may start to crystallize first. As a result, freeze concentration has a flexibility that opens many potential applications in a wide variety of industrial separation processes.

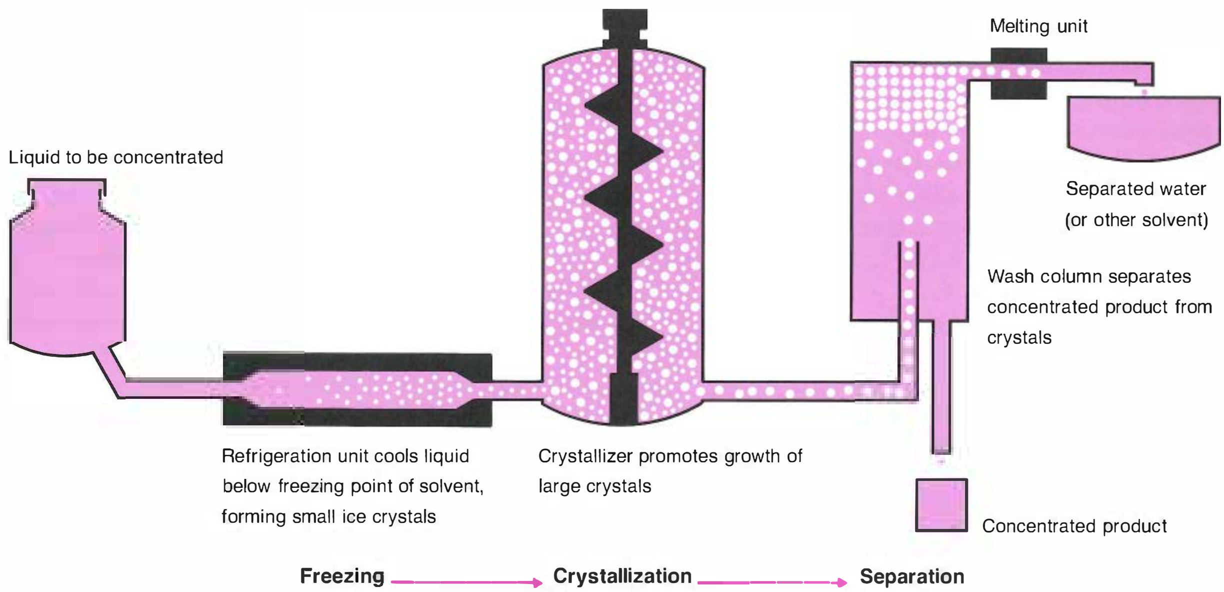
In so-called indirect freezing processes, a heat exchanger surface separates the refrigerant and the product solution. All freeze concentration involving food depends on indirect processes in order to avoid contaminating the final product with refrigerant.

In direct freezing processes, the refrigerant is an integral part of the solution being treated. An organic refrigerant can be mixed with wastewater, for example, then vaporized by exposure to a partial vacuum. Such vaporization cools the rest of the solution enough to form ice crystals.

The second major piece of equipment is the vessel, called a crystallizer, in which freezing actually takes place. In indirect process units, an important consideration in the design of the crystallizer is how to prevent solid material from accumulating on the heat exchange surface. Traditionally this has been accomplished by scraping the surface mechanically. The development of nonstick surfaces, however, along with new designs for directing the flow of process solution over them, has greatly improved the throughput capacity of crystallizers. Sometimes a separate holding tank is added to encourage the growth of large crystals, which are easier to process in subsequent steps.

The third major piece of equipment is a washer/separator, in which crystals are removed from the process solution and washed with pure liquid to remove surface contaminants. In some cases, a filter is used to separate crystals and solvent; in other cases, a simple wash column provides both separation and cleaning. If two kinds of crystals are formed (in a process known as eutectic crystallization), additional centrifuges or special sedimentation tanks may be required in order to separate them from each other.

In many applications a melter is added to the process to return solvent crystals to liquid form. The melting of ice crystals produced during freeze concentration of industrial wastes, for example, results in a stream of high-purity water that can be discharged without further treatment. Heat pumps provide an energy-efficient way to perform both the freezing and melting operations with the same compressor and refrigerant. □



sidered. DRINC laboratory personnel conducted blind tests of sensory quality, which produced the surprising result that both the reconstituted milk concentrate and the reconstituted powder were judged to have a smoother, creamier taste than a control sample of fresh commercial milk. Testing by the American Baking Institute Laboratory confirmed that the dairy powders produced by freeze concentration were quite suitable for cooking. Biological studies during extended operation showed that the cool temperatures inhibited the growth of microorganisms, so that the equipment would not have to be sanitized as frequently as evaporators.

An economic analysis of the operation indicated that once the technology has been demonstrated at commercial size, freeze concentration should substantially lower the cost of producing dairy products. Specifically, the cost of processing a pound of milk solids by using currently available freeze concentration technology is 1.3¢, compared with 2.8¢ for currently installed evaporators. Future freeze concentrators are expected to lower the cost to about 0.4¢ per pound. Scaled-up versions of freeze concentration equipment may also have a lower capital cost than evaporators, although the models that are currently available are considerably more expensive.

The phase 1 tests did indicate, however, that some technical problems need to be resolved during future work. In particular, freeze concentration at pilot scale with 1970s technology was not able to achieve the concentration level produced by evaporation. This finding is important because powdered milk is easier to produce from more concentrated liquids. As a result, further research will be conducted on the growth of ice crystals in dairy fluids, and attempts will be made to increase concentration by staging the freezing operation.

The phase 2 demonstration of freeze concentration in a dairy processing plant will use equipment with a capacity of 1000 pounds per hour—about one-fiftieth the size of a large plant. Despite its small size, this facility will make possible a semicommercial operation for determining the reliability, economics, maximum concentration, and sanitation protocol associated with the everyday use of freeze concentration. It will also provide large enough quantities of milk products to conduct market tests.

Wastewater treatment

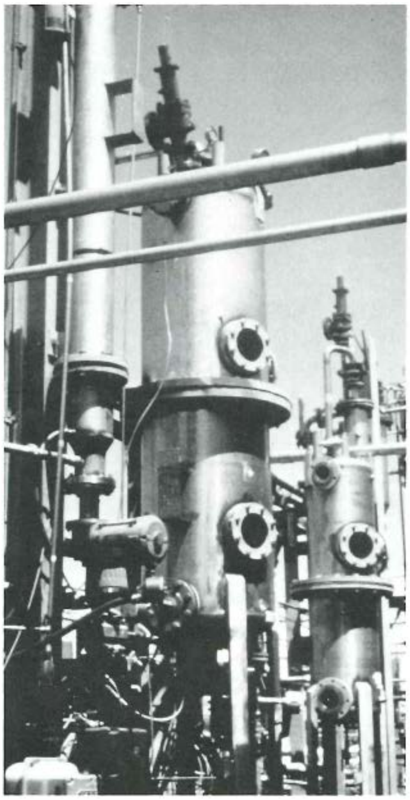
Another area in which new freeze concentration technologies could have a major impact is the treatment of industrial wastewater. Some pilot-scale work has already been conducted by equipment manufacturers and the industries involved. EPRI's concern, therefore, is to encourage commercial demonstration in some of the most promising applications.

In addition to reducing costs and energy use, freeze concentration offers several other advantages as an alternative to evaporation for treating wastewater. Lower temperatures make corrosion less of a problem, which often means that less expensive materials can be used in constructing containment systems. Useful by-products can sometimes be precipitated, with the purity of the crystallized solid material being in the "four nines" range (99.99% pure). The process is relatively insensitive to the type of waste being treated, so the quality of discharge water can be kept consistent. Air pollution is also avoided, since all volatile materials are kept within a closed system.

Both direct and indirect freeze concentration methods have already been tried experimentally for treating wastewater, often with the addition of a precipitate separator to remove solid waste materials that crystallize at the same time as ice forms. Test applications so far have included remediation of hazardous waste lagoons, concentration of deep mine reject water, recovery of process materials

Industrial Applications

Advances in freeze concentration technology have increased efficiency and throughput for the chemical processing and waste treatment industries. Pilot-scale projects are under way to demonstrate the feasibility of using freeze concentration for purifying organic chemicals and treating wastewater. Other promising applications include concentrating caustic soda, desalinating seawater, and concentrating black liquor produced in paper-pulp processing.



COMPARING COSTS OF CONCENTRATION

Application	Cost per Pound Evaporation	Cost per Pound Freeze Concentration
Fruit juice concentration	$2.45	$0.90
Sugar production	$3.84	$0.60
Desalting seawater	$0.84	$0.42
Caustic soda concentration	$1.01	$0.48
Black liquor concentration (paper-pulp processing)	$1.43	$0.69

from ammunition plant wastes, and by-product recovery from organic chemical and pharmaceutical waste streams.

Such wastewater treatment involves equipment very similar to that used in desalting seawater. A 55,000-gallon-per-day desalination plant based on freeze concentration has been operating for more than two years in Saudi Arabia. Preliminary experience at the plant indicates that freeze concentration can compete economically with existing thermal and membrane desalination technologies, which are used in the United States—for example, to produce drinking water in Florida.

An EPRI research project is now being planned that would use freeze concentration to treat wastewater in a metal-plating facility. Such treatment appears especially attractive because of its potential for recovering usable amounts of valuable plating metals. Under current practice, the water left after rinsing plated metal parts must often be carried long distances by truck for disposal in remote locations. As environmental regulations tighten, the cost of this disposal method is rising sharply.

"Rinse water from plating appears to be an excellent candidate for demonstrating the advantages of freeze concentration in wastewater treatment," says Amarnath. "Freezing will enable a plant to recycle both its water and metals that are now wasted, with very little discharge. EPRI has been working closely with an equipment manufacturer, a metal-finishing association, an electric utility, and a state pollution control agency in planning a project. Site negotiations are under way with a plating company whose disposal costs have become prohibitively high. We expect the demonstration to begin sometime next year."

Future plans

Another promising application currently being explored as a possible EPRI demonstration project involves caustic soda concentration in the chlor-alkali industry. Caustic soda (sodium hydroxide) is formed as a by-product of the electrochemical process that produces chlorine and hydrogen. As electricity passes through a brine, these gases are released at the electrodes, leaving behind a dilute caustic soda solution. Evaporators are now generally used to concentrate this solution from either 15% or 35% sodium hydroxide (depending on the process) to a commercial-grade 50% solution.

Because the chlor-alkali process is inherently energy-intensive, product costs are quite sensitive to improvements in efficiency, such as those offered by freeze concentration. Chlor-alkali plants are such large users of electricity that they already enjoy favorable rates, which make freeze technology even more attractive. Freeze concentration units are also expected to have a lower capital cost than evaporators, owing to their cool temperatures: because sodium hydroxide is less corrosive at these temperatures, equipment can be constructed from carbon steel rather than more expensive nickel alloys. The EPRI study conducted by Heist Engineering concluded that virtually all evaporators for concentrating caustic soda will eventually be replaced by freeze concentration units, since the new technology will offer returns on investment ranging from 27.5% to 40% per year, depending on the type of plant.

"EPRI is currently negotiating a demonstration project with a major chlor-alkali producer and its local utility," says Amarnath. "We are evaluating the choices between direct and indirect freeze concentration processes to choose the one that is likely to produce the greatest overall savings. We expect this question to be resolved within a few months."

Further in the future, demonstration projects will probably take place in several other industries, some of which may involve EPRI. The petrochemical industry, in particular, has already launched a small pilot-scale project to test the use of freeze concentration for removing hazardous organic waste from plant discharges. EPRI is monitoring this work closely. In addition, American, Japanese, and Swiss manufacturers are reportedly in various stages of installing commercial freeze concentration units in chemical plants for use in producing a variety of high-purity organic materials.

"I believe we are on the threshold of revolutionary changes in several industries because of freeze concentration," says Amarnath. "We expect to see this technology play a very major role soon in dairies, chlor-alkali plants, and some segments of the petrochemical industry. It will also be important in particular niches of wastewater treatment—usually where there is some recoverable material to help reduce costs. The impact on utilities will, of course, be indirect, but over the years they are also likely to experience a major positive effect." ■

This article was written by John Douglas, science writer. Technical background information was provided by Ammi Amarnath, Customer Systems Division.

Is Cost the Only Measure of Electricity Value?

The answer is no, according to researchers and a growing number of utility planners. As they come up with new demand-side management options, utilities are also finding many attributes of electricity service that customers value well beyond a lower cost per kilowatthour.

"The question is, Mister Gordian, whether the money we save on lighting is worth these pile-ups in the corridors at lunch time."

Integrated value-based planning (IVP) is a new way to estimate, influence, and balance expectations of future electricity supply and demand. It's just now taking shape, being modeled, and even being tried on for size by a few utilities. As a rational, structured methodology, IVP is new. But pieces of it are familiar and have been used for years.

IVP begins with the utility customer. It involves identifying and evaluating the nature of electricity as seen by its users—and, on that basis, planning for the packaging and delivery of electricity service. Market research is an element here: establishing the values that customers of all kinds place on the products and services they use, then examining the service options that can be formulated to fulfill those values.

IVP may begin with the concept of value to the customer, but it also has to consider the utility's costs and profitability, and it must do so in a business environment that's being restructured, where regulation and deregulation coexist.

Relating cost and value

While the absolute cost of utility service remains important in IVP (competition is always an incentive to minimize cost), it has to be considered in the context of the value of that service in the customer's mind. If utilities focus their planning on the single attribute of electricity cost, they'll not be able to furnish other attributes that cost more than the "bare bones" service. This is an important premise, and it's becoming more evident as U.S. suppliers of all kinds tailor their offerings to fill specialized market niches.

Convenience, safety, and reliability are attributes of electricity that utilities themselves have long emphasized. But even these are being exploited by nonutility marketers who identify and fill niches—market segments where the values of enhanced service are greater than the prices paid. A clear-cut example is the customer who buys standby generating equipment to gain greater reliability than the utility provides. Another example is the small commercial firm that turns down unfamiliar energy management equipment because of the risk involved, but then participates in a shared-savings program where a third party owns and operates the system.

Phil Hanser, a senior project manager for EPRI who specializes in utility planning research, sees three criteria that IVP must satisfy if it's to be a widely used and useful tool for utility planners. "First, the process has to uncover all the electricity service attributes that customers might like to have. It's got to accommodate new ones that emerge, too.

"Second," he continues, "IVP has to be structured to ensure that a given service can be priced competitively for the value offered. This isn't open and shut. Electricity cost itself is affected by many variables—I think especially of generation mix and time of day." Hanser also points to new accessory equipment and service activities—packaging and delivery costs, really—for which most utilities just don't have any precedent.

The third criterion for successful IVP is to maximize the net value of service, that is, the difference between its cost to the utility and its value to the customer. In this connection, Hanser is emphatic about one thing. "We're not talking about pricing electricity at whatever the market will bear. That doesn't meet either the spirit or the letter of regulation. New service options have to be priced up from cost, the same as now."

Hanser makes the appealing point that when you must turn away from the very highest priced service possibilities, you also forestall the highest risk. "The point of IVP," he says, "is to find and add options that will improve the outlook for earnings in line with regulatory policy. Offering a lot of very high priced services can put a utility's authorized rate of return at greater risk."

Seen in this light, IVP should help a utility stabilize both its costs and its earnings. It's being developed as a rational methodology for costing and pricing electricity that has values beyond its kilowatthour quantity alone.

Reconciling policy values

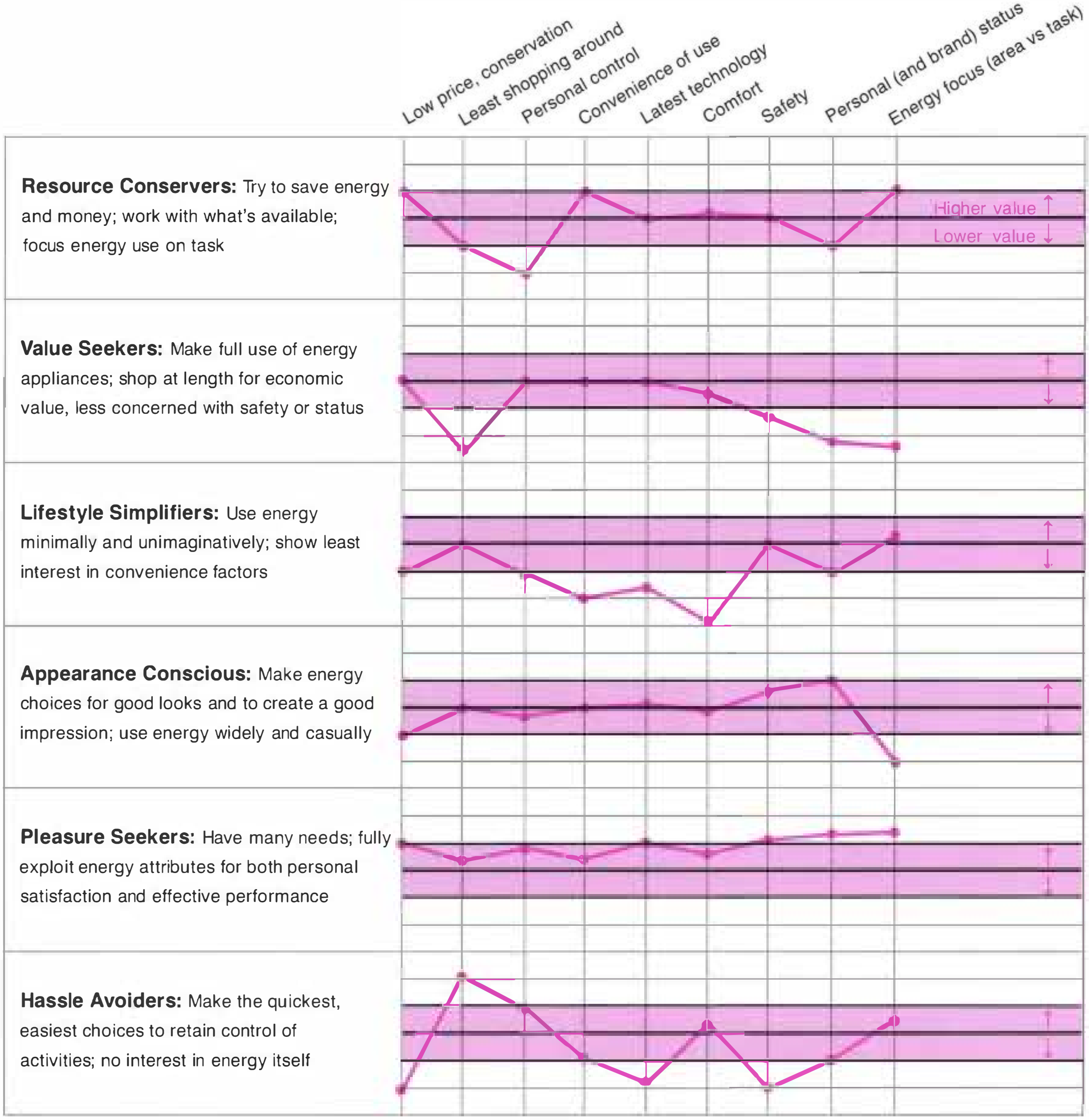
Integrated value-based planning is a recent addition among the methods used by utilities in the United States today. It differs somewhat from the least-cost planning (LCP) processes widely followed by utility regulatory commissions and other policy bodies. Everyone uses the same measurement unit, dollars and cents, but the various parties can and do diverge on the connotation of value.

LCP seeks to establish the scrupulously lowest absolute cost for a kilowatthour of electricity. LCP thus tends to be single-valued, responding to just one customer motivation, economy, maximized by low energy usage. In contrast, IVP seeks to establish the least cost at which a kilowatthour can satisfy one or more other customer motivations. Usually somewhat higher than the traditional least cost, a value-based cost is the net result of both incremental additions and subtractions. The appeal is that IVP responds to a greater range of customer circumstances, needs, and desires—and it does so on the basis of the rationally derived cost to fulfill them.

Whatever the merits of integrated value-based planning, it won't become the industry standard overnight. Least-cost planning is also becoming more consistently defined, thanks in part to a planning handbook published last October by NARUC, the National Association of

Residential Customer Preferences

Perceived values for each of nine variables produce six distinctive profiles of U.S. residential electricity customers. Low kilowatthour cost is especially important to two of the groups (which together make up about 38% of all residential customers), but priorities diverge on other attributes of electricity service. Value-based planning introduces methods of assessing those attributes and designing electricity service options accordingly.



Regulatory Utility Commissioners. And *Public Utilities Fortnightly*, the journal of the regulatory community, recently editorialized that the "era of LCP is only just beginning."

Why is this? The policy appeal of LCP seems to stem from its encouragement of energy conservation, which is definitely a general social value if not a specific economic one in all circumstances. LCP places the costs of demand-side management on an equal footing with the costs of additional electricity generation. This "level playing field," as it is called, considers electricity supply-side options and demand-side options as apples and apples according to the only measure used to compare them, cost. When new power facilities are for the most part more expensive than other options—when new capacity costs more than the equivalent conservation—LCP indeed gives the nod to demand-side measures.

But it does so only with respect to the actions of utilities. Many electricity users remain free to choose suppliers, aided by technology, commercial opportunity, and even public policy that is in some respects ambivalent. For utilities to develop and implement IVP effectively, policymakers must be convinced that it will work in a regulated context and that customers will benefit from the change. Today's electricity markets, seen quite apart from the utilities and others serving them, are therefore drawing close interest from policymakers.

William Smith, another senior research manager in EPRI's demand-side planning, noticed this at a conference on IVP that EPRI sponsored late in 1987. In addition to 200 utility representatives, the participants included at least 50 regulatory commissioners or staff members, plus others from federal agencies and public power boards. According to Smith, "The opportunity to discuss utility planning issues in a detached way revealed that utilities and policymakers don't necessarily have opposing interests. People were coming together who, in effect, had never been in the same room before. Their only other interaction had been while giving testimony in hearing rooms."

In their management of EPRI demand-side planning research, Hanser and Smith see IVP as a competitive technique for utilities in a business setting that is simultaneously regulated and deregulated. There is more than a suggestion that IVP can help level the playing field in a different sense than does LCP—by making possible the use of surplus generating capacity, for example. A number of U.S. utilities have plants in their rate bases (i.e., plants whose costs are reflected in utility rates) that don't serve some loads only because the utilities aren't allowed to add the cost of auxiliary services (values) some customers want—and those customers have taken their business elsewhere.

This points up one of the three main reasons why IVP may produce a better systemwide outcome than LCP. When kilowatthour cost is the only permitted selection criterion, then a utility's choice of service options is limited. To that extent its program may not be in the overall best interest of its customers.

Second, IVP provides utilities a way to prevent the one-by-one competitive inroads that they often aren't permitted to counter today. Competitors seek and fill niches, utility total revenue falls, and average service rates tend to rise accordingly.

Finally, IVP works to correct a narrow definition of product and service that is stifling, resulting in lost opportunities among customers of all kinds. And it comes just at a time when every U.S. business and industry has the natural incentive—in an increasingly competitive climate—to innovate to the greatest possible extent.

Putting the customer first

What are the values to be found in electricity service? Are they new? For many people who came into utility work through such vocational doorways as engineering, generation, and T&D, the surprise is that the phenomenon of electricity itself isn't a value. You have to look beyond the meter, beyond the outlet, at what electric energy is doing, why, and under what circumstances.

Electric light, heat, and motive power have been elaborated and augmented unbelievably since Edison's time. Given the proliferation of energy appliances and controls today, many more services can be performed, many more values fulfilled. Electricity's long-standing attributes of reliability and convenience are only the beginning. Furthermore, technology increasingly enables the attributes of electricity service to be separated from each other—unbundled.

Industrial operations and processes have been the first to document unbundled electricity values, because energy is an accountable factor of production and energy forms can be rated, dollarwise, on such bases as precision, portability, speed, cleanliness, safety, variability, and the like, as well as on the common quantitative basis of Btu content. Some industrial operations require less overall energy in electric form because, say, of electricity's precision in a particular application. Equally significant, other operations may need more electric energy but yield such savings in materials, time, or labor that productivity overall is improved.

Residential electricity users also point to specific attributes that have value, however subjective it may be. According to a 1987–88 study directed by EPRI's Larry Lewis, the most frequently cited qualities are safety, comfort, freedom from outside control, appearance, convenience, economy, and a sense of caring on the part of the supplier. Not surprisingly, these attributes—and their perceived, subjective value—vary from one customer class to another, and even by segment within a class. One householder may set great store by convenience, comfort, and freedom from outside control,

Evolution in Plannin

Least-cost planning, integrated resource planning, integrated value-based planning—these terms have come into the electric utility lexicon during the last 20 years. They all refer to ways of optimizing electricity supply and service relative to the level and shape of demand.

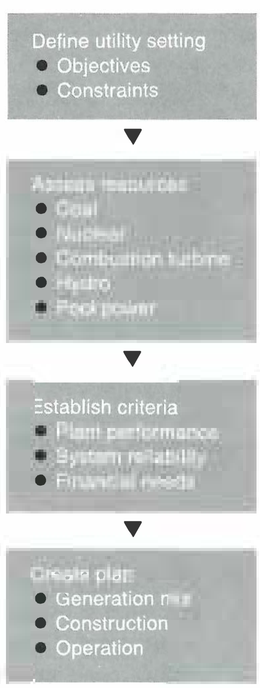
But the terms—and the methods behind them—haven't come into fashion simply to create an illusion of something new. They've come about because the times demanded them.

Stability used to be the hallmark of the utility business. The primary need was to identify and provide the least-cost electricity supply resource to meet growing electricity demand. Stability meant certainty; even the growth was uniform. And neither the regulatory environment nor the costs of doing business carried much uncertainty for electric utilities. They competed with other energy fuels and forms largely on a cost basis, benefiting from economies of scale. The planning process goal of minimizing future revenu requirements encouraged this singl measure of competitive success. Thi was the least-cost planning appropriate for the time.

Cost and price stability vanished i the 1970s, when utilities and everyon else experienced the sharp and speci shock of the run-up in fuel cost tha began with the OPEC oil embargo. Other economic dislocations sen equipment costs and interest rate to new highs. Electricity deman

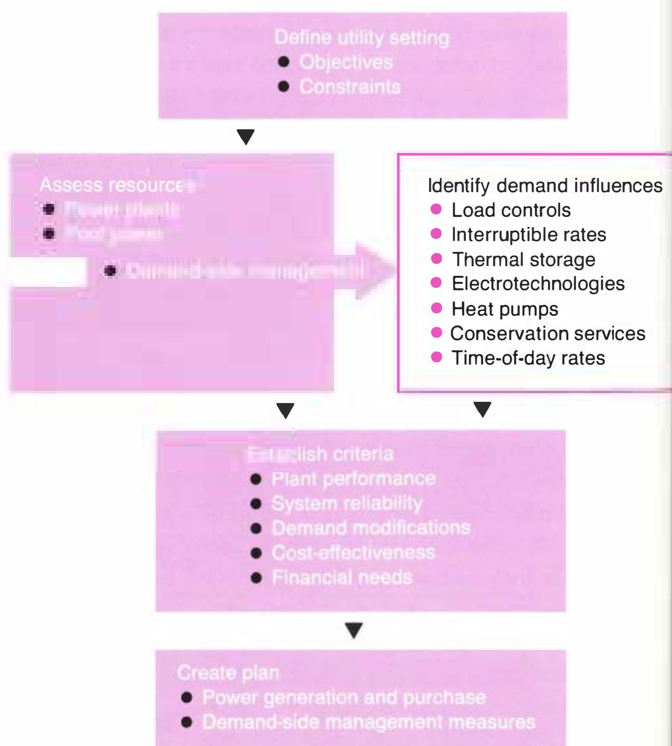
Traditional Least-Cost Planning

Supply-side planning to minimize utility's overall revenue requirement in a regulated, stable economic setting



Integrated Resource Planning

Supply- and demand-side planning to minimize utility's overall revenue requirement in a regulated but unstable economic setting



Working Up to the Cost of Value

dropped and patterns of usage went haywire. Expensive provisions for pollution controls had to be accommodated, adding their own unprecedented costs to the new uncertainty.

Especially because of the much higher capital cost of new power facilities, which pushed rates and customer tempers further upward, utilities began to plan and adopt demand-side management measures that affected electricity usage—changing the daily or seasonal pattern of demand or reducing its growth. The goal was still to minimize costs, for both utility and customers, in significant measure by avoiding or deferring the need for new system capacity. Utility planning thus took a new turn, motivated both by the economic cost of energy and by the perceived but not quantified cost of our depletion of fuel resources.

Integrated resource planning, as the process came to be known, led some utilities to insulate customers' houses when that was a cheaper alternative than delivering the electricity needed to heat them. This and other demand-side management options were the first structured steps in modifying the concept of electricity as a product and introducing the service dimensions of variable reliability, risk, and convenience. Direct control of customer load, either of specific equipment or under an interruptible-power agreement for peak load periods, is an example.

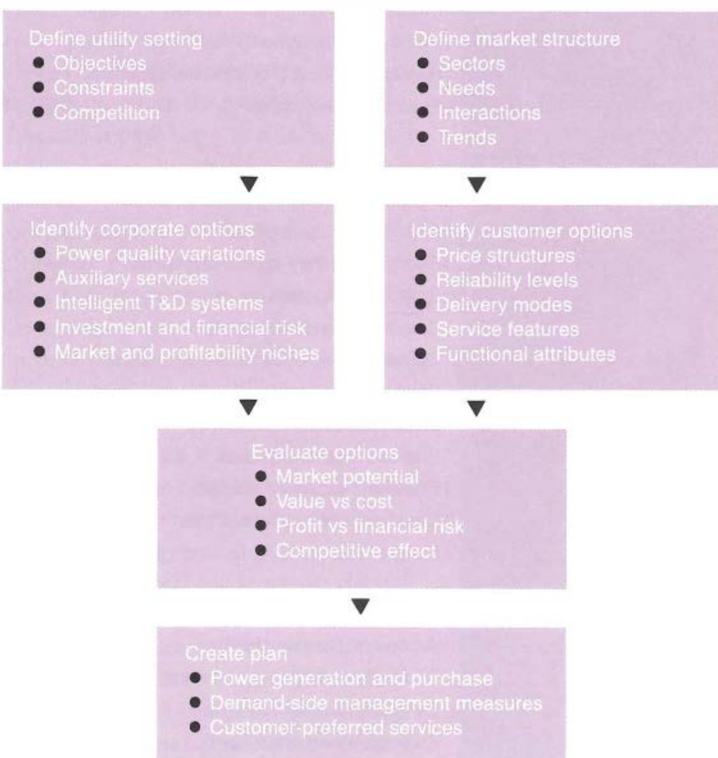
Changes in service obviously require customer acceptance, and the 1980s have seen utilities pursue a research agenda aimed at better understanding customer needs and preferences. A considerable body of data makes it clear that some customers put a premium on convenience and others on reliability. It's also becoming apparent that these variations occur even within defined market segments; that is, two otherwise identical customers may exhibit very different preferences. The researcher's term for this is market segmentation.

Moreover, additional attributes of electricity service are becoming apparent, and technological advances are increasingly making it feasible to "unbundle" those attributes for still more tailored customer satisfaction.

Utility planning now incorporates market research and application engineering to document electricity value, both qualitatively and quantitatively. Especially as utilities now find themselves in direct competition with other factors as well as other fuels, there is need for a planning process that explicitly takes customer values into account, even while the price of electricity remains based on the cost to fulfill those values. □

Integrated Value-Based Planning

Supply- and demand-side planning to maximize combined net value to customer and utility in a regulated but unstable and competitive economic setting



all of which depend in part on reliability of service. Another householder may shrug at such certainty and wish for greater economy—through an interruptible rate like those negotiated with commercial power users.

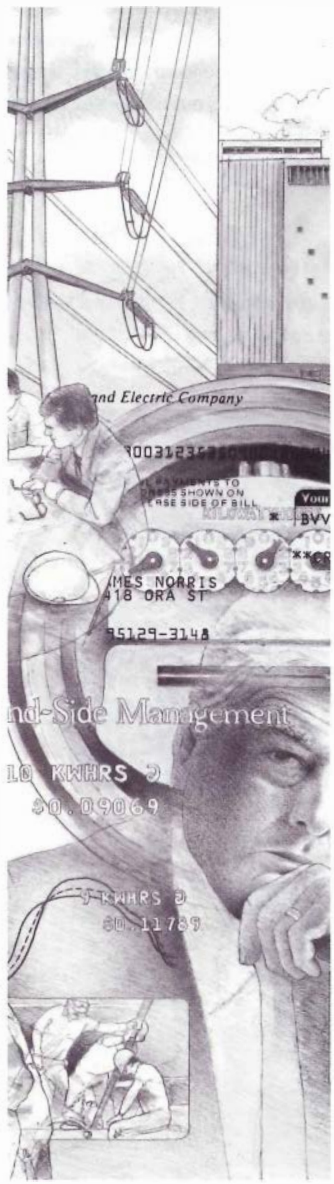
Until very recently, utilities made only limited efforts to match electricity service attributes to customer values. But competing suppliers of fuels (gas, oil, wood), equipment (cogeneration, appliances, controls), and services (financing, management, operation) have aggressively applied their expertise in specific circumstances to offer entirely new functions or add value to traditional ones.

Matching service attributes to customer values is more difficult for a utility than for other prospective suppliers because the needs of overall system operation must be taken into account. For example, to flatten its overall load shape, protect reserve margins, and minimize capital outlays for new generating capacity, a utility might encourage all its customers to install fluorescent lighting in place of incandescent. This can prove to be inappropriate for some users, even entire classes. A restaurant owner objects that the shape of the tubes and fixtures doesn't fit into the decor, a clothing retailer worries about how the fluorescent spectrum distorts merchandise colors, and a homeowner is put off by the idea of "office lighting." The lesson here is market research, including market segmentation research. The motivation to cut peak load is valid, but the program can be adjusted to target customer classes whose values are consistent with fluorescent lighting—offices, schools, and industrial facilities.

This example highlights the existence of two groups of residential customers broadly defined by EPRI research as resource conservers and hassle avoiders. Conservers put much greater value on low cost than on other attributes. Hassle avoiders have their eyes on entirely different objectives: they look for every opportunity to minimize difficulty in establishing or using electricity service.

Utility Service Options

Many valuable adjuncts of electricity service have become evident in utility and EPRI studies, although only a few are widely available so far, notably interruptible rates and loans for energy-efficient equipment. Some of the new service options yield savings for the utility and discounted rates for the customer. Others entail added costs for both, but they provide degrees of certainty, control, assistance, or convenience that various customers value more highly.



Service Certainty
Interruptible service
Utility control of load
Dedicated repair crew
Local backup generator
Outage insurance

Price Control
Changed energy form (e.g., hot water)
Contracted-term rate
Demand-cap rate
Economic development rate
Prepayment at meter
Real-time pricing (hourly meter record)
Futures-market prices

Application Assistance
Electrical equipment advice
Energy efficiency improvement loan
Building design advice
Cogeneration joint venture
Customer employee training
Electrical repair referral
Electrotechnology advice
End-use equipment lease
End-use equipment service
Customer operations analysis
Safety audit

Account Convenience
Company-wide billing summary
Dedicated account service
End-use billing breakdown
Rate and billing analysis

Utility objectives and options

Considering customer values first does not mean that IVP neglects utility values. As suggested by the example of fluorescent lighting to help flatten a load shape, the utility's technological, organizational, and financial objectives all have to be incorporated in its planning process. The IVP goal is to maximize the *net* value of electricity to both parties in the transaction.

Technology offers perhaps the clearest examples and possibilities of electricity service options. Some can be provided today; others require new hardware. For example, how can power quality be varied among customers on the same system? Is it practical—or advisable—to vary frequency? Are there system hardware implications in considering prepaid utility service? What would be the system impacts of distributed power generation on a large scale? What would it take to meter electricity being wheeled through a system to individual retail customers? Can a distribution outage somehow be "routed around" customers who are paying a premium for reliability?

Organizational form is a sensitive but necessary area for change when IVP is considered or commenced. Most utilities are organized today in a way that satisfies traditional planning needs—with separate groups responsible, respectively, for rates and revenue requirements, generation and transmission, distribution and service, corporate planning, and so on. Coordination and approval would conceivably be difficult if a single customer's value perceptions called for, say, a negotiated rate, extra reliability, multiple-account metering and summary billing, and some technical guidance on electrotechnology applications.

A possible future might see a utility organized into profit centers, their capabilities matched to the values of market segments or customer classes. But even if planning remains centralized, implementing the findings of IVP is bound to be decentralized, because the process originates with the customer. Having begun with market research, it is, so to speak, planning from the bottom up instead of from the top down, and the "match" at the utility-customer interface is an important index of IVP success.

The idea that electric utilities can differentiate their service into a spectrum of options is central to the IVP process. But this doesn't mean diversifying into soap and hamburgers. Utilities already can and do adjust some service characteristics. Indeed, early concepts of IVP focused on the ability to vary reliability of service.

Interruptible service to self-selected large customers is one example, giving the utility needed increments of capacity at critical times in exchange for a discounted rate. Brief on-off cycling of residential appliances on a rotating basis is another example, as is the cycling of air conditioners by special control signals. The heart of such measures is defining and tailoring them to customer preference—or at least acceptance.

Other than reliability and cost, some of the major service variables, all with implications of value, are differential rates for time of use, long-term supply guarantees, billing breakdowns by end use, outage insurance, cogeneration partnerships, real-time electricity pricing, prepaid service, and equipment leasing and financing.

Whether or not utilities formally adopt IVP, there's evidence of its use, piecemeal perhaps, but not in the least tentative. Peter England, who directs marketing services at Florida Power & Light, points for example to the use of service value as a planning strategy since 1981. That's when the utility began a total quality control program along classic Japanese lines, establishing customer satisfaction as the measure of success.

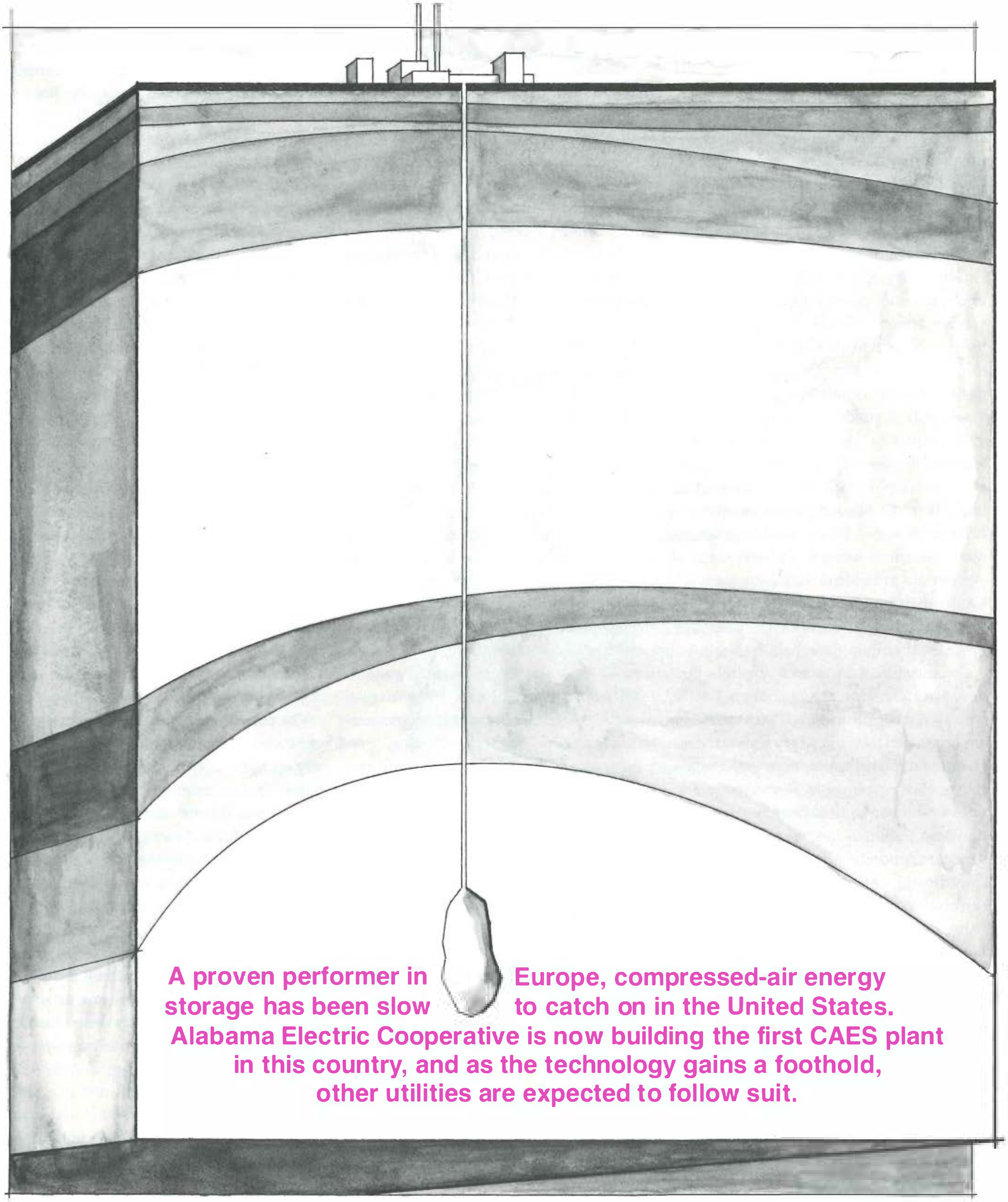
England also cites FP&L's reliance on field personnel to spot new service opportunities. For example, barred windows in a number of Miami neighborhoods suggested a security need that could be also be met by auxiliary lighting. Some customers accepted; when others declined because the available lamps would spill light on neighbors, FP&L came back with more lamp styles and won a few more installations.

Another utility, Texas Utilities Electric Co., is pressed for generating capacity in a market area where 90% of its customers have air conditioning. Thus the utility aims for load management flexibility through such demand-side measures as preferential rates for interruptible service and off-peak energy. "We're constantly on the lookout for ways to enhance service," says Carroll Benson, manager of information and statistics, "but when we find one, we have to compare its cost with the customer's willingness to pay."

Benson adds that TU Electric is even making a pitch to hold customers who are weighing the economy of cogenerating their own steam and electricity. There's value in their staying continuous utility customers, he says. "Cogeneration may indeed be a bit cheaper now, because they can still get us to pick up the slack when needed, but in a few years we may not be in a position to do so."

The combinations and permutations of electricity service cost and value are virtually endless. Computers, power technologies, and a customer orientation today make it possible for mass marketers to exploit niches also. Just as location is said to be the first three criteria of real property value, competition is fast becoming the overriding consideration for electric utilities as they shape and serve load. Integrated value-based planning recognizes the economic stakes of utilities and their customers alike, and it does so on a rational basis designed to serve the public interest at all levels of the economy—local, state, and federal. ■

This article was written by Ralph Whitaker, feature editor, drawing on a paper by Philip Hanser and William Smith of EPRI's Customer Systems Division and John Chamberlin of Barakat, Howard & Chamberlin.



A proven performer in Europe, compressed-air energy storage has been slow to catch on in the United States. Alabama Electric Cooperative is now building the first CAES plant in this country, and as the technology gains a foothold, other utilities are expected to follow suit.

PIONEERING CAES FOR ENERGY STORAGE

Breaking ground for a new power plant is an auspicious occasion for any utility, but for Alabama Electric Cooperative last October's ground-breaking ceremony was especially notable. In close partnership with EPRI, the utility is building the first commercial compressed-air energy storage (CAES) plant in the United States, and only the second such plant in the world. Other utilities are watching the project closely, and a successful demonstration of CAES technology in Alabama should lead to its widespread application in this country.

When the 110-MW plant comes on-line in 1991, it will use off-peak baseload electricity to compress air into a 19-million-cubic-foot cavern mined from a salt dome. When electricity is needed to meet intermediate and peak demand, the compressed air will be withdrawn, heated with natural gas or oil, and then run through a turbine to produce power. In addition to generating electricity relatively inexpensively when it is most needed, the plant will burn about one-third the fuel of a conventional combustion turbine and thus emit one-third the pollutants. Even more significant, the CAES facility will allow the utility to make more effective use of its baseload coal units by operating them at a higher and more efficient level of power output.

Energy in reserve

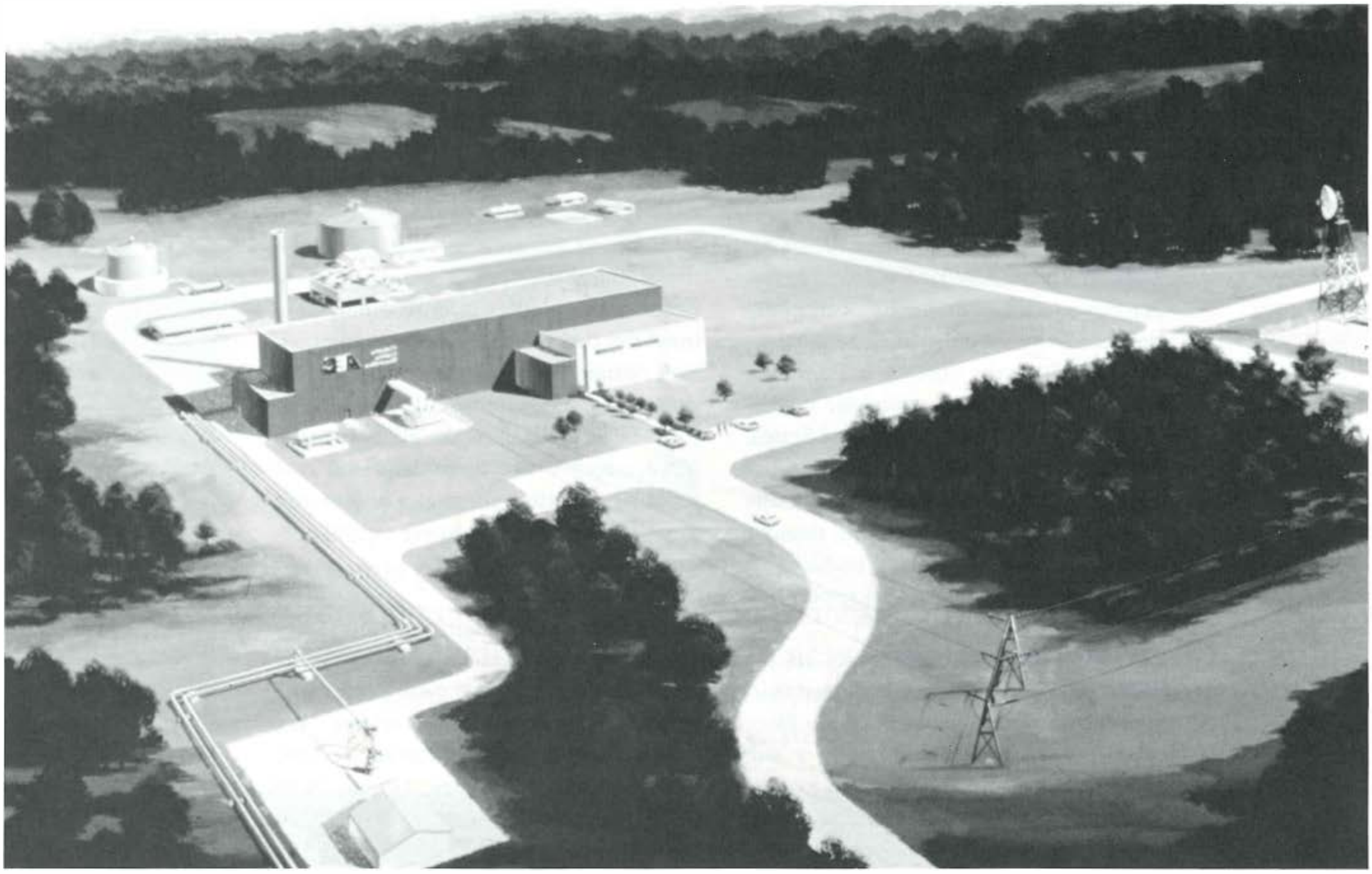
In the light of a changing economic and regulatory environment, and the climbing costs of producing peak power, the benefits of energy storage systems are being increasingly appreciated by EPRI and the utility industry. Unlike most other commodities, electricity must be used as soon as it is generated, so utilities

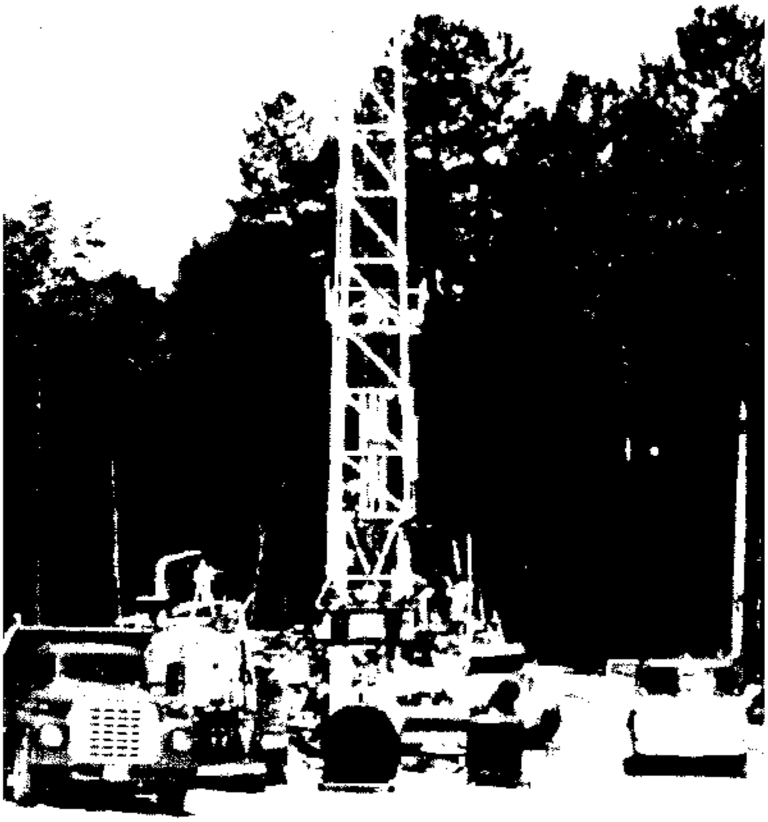
Breaking New Ground in McIntosh

Site preparation and cavern construction are under way for Alabama Electric Cooperative's 110-MW compressed-air energy storage plant. Located 45 miles north of Mobile, the McIntosh plant will be the first CAES facility in the United States.

Ground-breaking ceremony

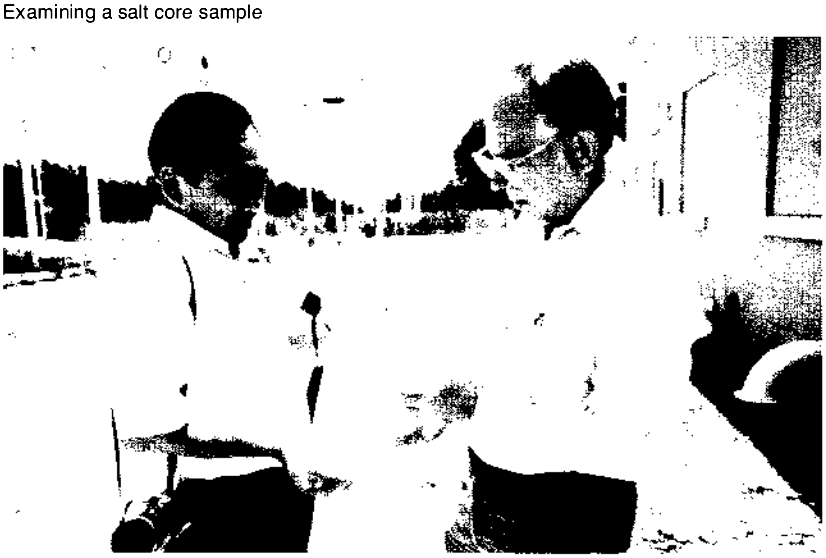
Artist's concept of the McIntosh plant





Drilling a test well into the McIntosh salt dome

Examining a salt core sample



produce power to match the swings in customer demand. Power companies cut back production as usage drops off at night and boost production as demand rises during the day, using a mix of generating equipment to meet the load in the most cost-efficient manner.

Baseload units—large coal, nuclear, or hydro plants—provide power around the clock because they are more reliable and economical if run continuously. Typically such plants produce an excess of power during low-demand periods and a shortage when demand is high. As demand begins to climb in the morning, intermediate units are started up, and their power production is gradually increased in response to the rising demand. As demand begins to tail off, the intermediate units begin throttling back their output. To meet peak demand, which typically lasts a few hours each day, the baseload and intermediate units are supplemented with combustion turbines burning oil or natural gas. The use of these premium fuels makes peak power the most expensive component of the generation mix. Furthermore, oil and gas may be subject to rising prices and uncertain supply, and many utilities are wary of committing to their use.

If the inexpensive surplus baseload electricity produced when demand is low could somehow be stockpiled to meet intermediate and peak demand, it would cut consumption of premium fuels, allow the baseload plants to run at a more efficient rating, and improve a utility's flexibility in matching its generation to customer demand.

"Storage could also prove to be a particularly attractive option for an aggressive utility in a deregulated industry," says James Birk, director of EPRI's Storage and Renewables Department. "Storage can strengthen a utility's negotiating position relative to independent power producers and, at the same time, assure customers continued high reliability of service despite the uncertain reliability of the primary generating system. Also, storage can become the hub of a utility, just as selected airports are hubs for airlines. In each case the hubs serve the same purpose: to organize and use production and delivery systems to meet demand in the most profitable way."

The only energy storage technology in widespread use today is pumped-hydro storage, in which water is pumped uphill during off-peak hours, then released to run through turbines when demand increases. However, pumped-hydro plants cost over $1000/kW, even at the large, 1000-MW plant size. A plant can take about 10 years to build and is constrained by siting requirements; a pumped-hydro system requires a large amount of real estate with suitable topography for the upper and lower reservoirs. Many of the best sites are already taken, and proposed plants may face a gauntlet of environmental opposition and lengthy permitting procedures. Batteries and superconducting magnets are also being developed to store off-peak energy, but these options are not yet commercially available at an attractive price.

Rise to power

Compressed-air energy storage offers an alternative to these other storage technologies. In concept, CAES can be compared to pumped hydro, except that air is used instead of water and the storage medium is an underground chamber instead of an elevated reservoir. The compressed air for a CAES plant can be stored in several types of underground structures, including caverns in salt or rock formations, depleted natural gas fields, and salt-water-bearing aquifers.

A CAES plant can be described as a simple combustion turbine that has been modified to operate in separate compression and generation cycles. Like a conventional combustion turbine unit, the CAES plant has a compressor, combustor, turbine, and generator. A CAES plant has additional features in the form of the storage chamber and a combination motor-generator that does double duty, powering the compressor during the charging cycle and producing electricity in the generation cycle. It is the split-cycle operation that makes CAES so cost-effective. The fuel used for compression is cheap baseload electricity taken from the grid during low-demand hours. This means that during the generation cycle the CAES turbine does not have to power a compressor, unlike a conventional combustion turbine unit. Because the air entering the CAES turbine is already compressed, all of the turbine's energy is used to generate electricity. The Alabama Electric Cooperative CAES plant will use about 0.82 kWh of electricity and 4100 Btu of oil or gas for every kWh of output. In contrast, conventional gas turbines burn about 12,000 Btu of premium fuel per kWh generated.

Because some fuel is burned in the generation cycle, CAES is not a pure storage technology, explains Robert Schainker, who has spearheaded EPRI's CAES research as manager of the Institute's Energy Storage Program. "Compressed-air energy storage is unique; it's a hybrid technology that uses electricity for compression and fuel for generation, performing each process in the most efficient manner. Compression is done at night, allowing baseload units to run at a higher rating, which is a great benefit, and generation is done in the afternoon, displacing relatively expensive power while using far less premium fuel than would a conventional combustion turbine."

Proven, flexible, economical

Although the technology may sound exotic at first, CAES is no futuristic pipe dream. A compressed-air facility has been operating successfully since 1978 in Huntorf, West Germany, and CAES technology is gaining momentum in other nations as well. In its 10 years of commercial operation, the 290-MW (50-Hz) Huntorf plant has racked up an impressive performance record, demonstrating 90% availability and 99% starting reliability. In addition to fuel savings and load-leveling benefits, the Huntorf plant has demonstrated how a CAES plant can increase a utility's flexibility in managing its load. Because it can quickly change its power output with minimal change in efficiency, a CAES unit can respond swiftly to rises and dips in demand and can provide regulation and spinning or emergency reserve.

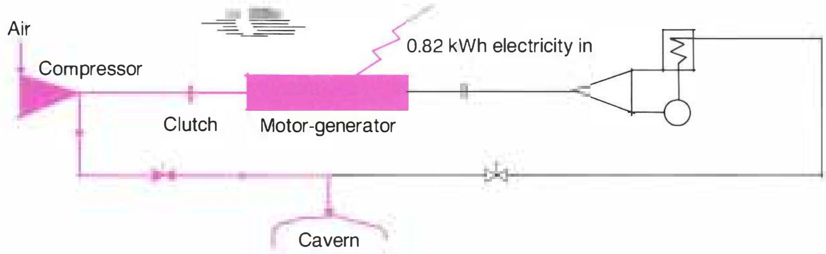
Spurred by the plans for and success of the Huntorf plant, EPRI launched a series of economic and technical studies in the late 1970s to determine if CAES could also work in the United States. In partnership with the U.S. Department of Energy and several interested utilities, EPRI investigated the use of hard-rock caverns, salt domes, and aquifers for storing compressed air, and developed plant design criteria and estimates of costs, schedule, and technical risks. The studies confirmed that CAES was technically feasible and economically viable, and that three-fourths of the United States had geology potentially suitable for underground air storage.

A hurdle remained, however. The only CAES system being offered in the late 1970s was a 220-MW (60-Hz) unit from Brown Boveri that was based on the Huntorf design. Recognizing that U.S. utilities were not ready to take on the risk of pioneering a new breed of power plant on such a large scale, EPRI sought to determine whether the technology could be downsized. "We started looking at the feasibility of smaller units, 25-MW to 100-MW plants, what we now call mini-CAES plants," says Schainker. "We hired both Brown Boveri and Dresser-Rand to look at the economic and technical capability of the smaller machinery, and we hired Energy Storage & Power Consultants to do overall plant integration studies; we found that there were both U.S. and foreign manufacturers for the turbomachinery components in smaller sizes, especially serving the petrochemical industry, and that the smaller sizes were economically attractive—both on a

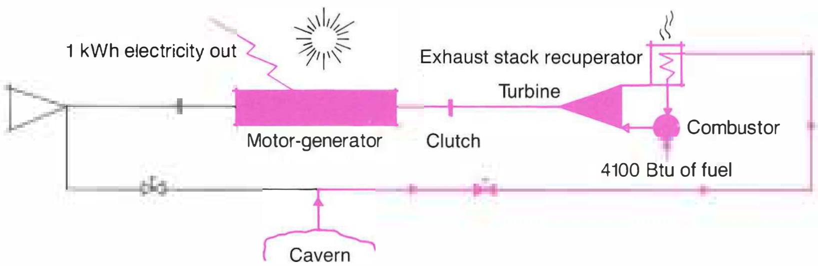
CAES in Operation

A CAES plant stores off-peak baseload energy in the form of air compressed into an underground reservoir. The design can be compared to a conventional combustion turbine plant that has been split to perform compression and generation in separate cycles. Clutches connect the compressor and turbine sections to a combination motor-generator, allowing each section to operate independently during the appropriate cycle.

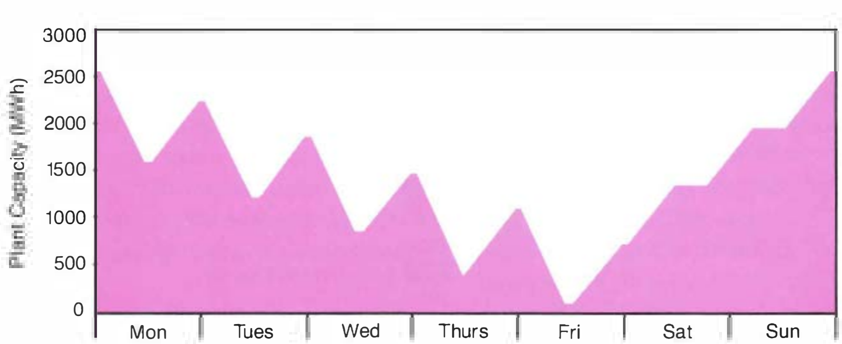
Compression To charge the reservoir, the compressor clutch is engaged and the turbine clutch is disengaged. Powered by baseload electricity from the grid, the motor-generator drives the compressor, and the compressed air is then delivered to the underground cavern for storage.



Generation In the generation cycle, the motor-generator is engaged to the turbine and disengaged from the compressor. The compressed air is released to run through the heat recuperator and into the combustor, where it is heated by gas or oil for expansion through the turbine. Preheating the air in the recuperator reduces fuel consumption by 27%.



Weekly Operating Cycle The large cavern of Alabama Electric Cooperative's CAES plant will allow the utility to take advantage of inexpensive electricity to compress air on weeknights and over the weekend. In a typical week of operation, the plant will start with a fully charged cavern. It will generate about 10 hours per day and be partially recharged each weeknight, as depicted in this sawtooth curve. On Saturday and Sunday nights, when electricity is least expensive, the cavern will be brought back to its full charge.



unit cost basis and because of their modularity and much shorter construction time."

EPRI's research on the feasibility of mini-CAES plants revealed that the smaller units retained the attractive features of larger plants while offering additional benefits. The combination of reduced lead time and smaller building blocks lowers the risk and cost of installing excess capacity, provides a better match with load-growth patterns, reduces the cost of borrowed capital, and opens up attractive alternative financing methods. In addition, the modular turbomachinery trains allow a plant to be matched to the specific size and capacity requirements of a particular utility.

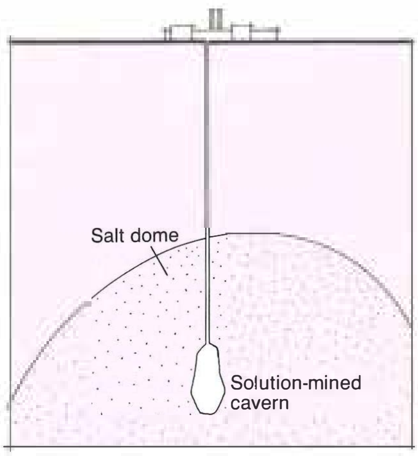
"CAES technology is applicable to many utilities," says Schainker. "Our studies show that CAES could supply about half of the nation's energy storage capacity by 2020. Based on simplified marketing studies this amounts to about 5–15 GW of capacity, and it is important to note that geological considerations do not appear to be the limiting factor. Suitable geology can be found in just about every major utility service territory. The turbomachinery is available off the shelf in sizes ranging from 25 to 220 MW; it is available from U.S. and foreign vendors and comes with standard warranties." What's been missing up to now is a CAES plant in the United States to provide utilities here with hands-on experience in the technology. That void will soon be filled by Alabama Electric Cooperative's McIntosh plant.

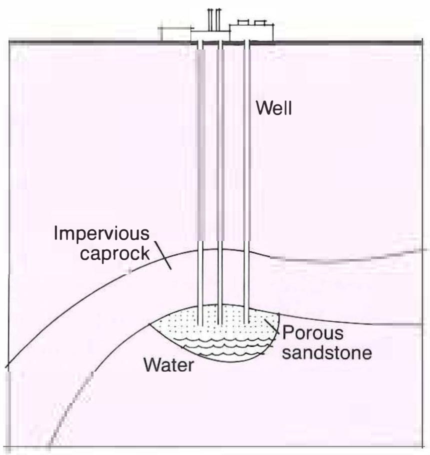
Pioneering CAES

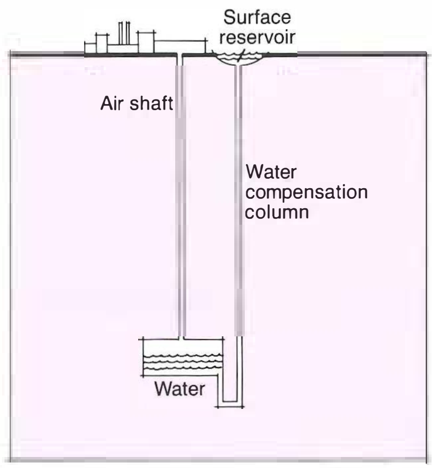
With customer demand growing at an annual rate of 3–5%, Alabama Electric Cooperative was in the market for new generating capacity. The utility's service area consists mostly of rural residential customers, and the daytime demand for electricity is nearly double what it is at night. AEC's current generating capacity is 685 MW. Coal-fired steam units contribute 592 MW of the total; two small hydro

Siting CAES Plants

A key requirement for a CAES power plant is a site with geology suitable for developing an airtight underground reservoir. Compressed air can be stored reliably in aquifers or in caverns mined from salt or rock formations. EPRI studies show that approximately three-fourths of the United States could provide potential CAES sites.



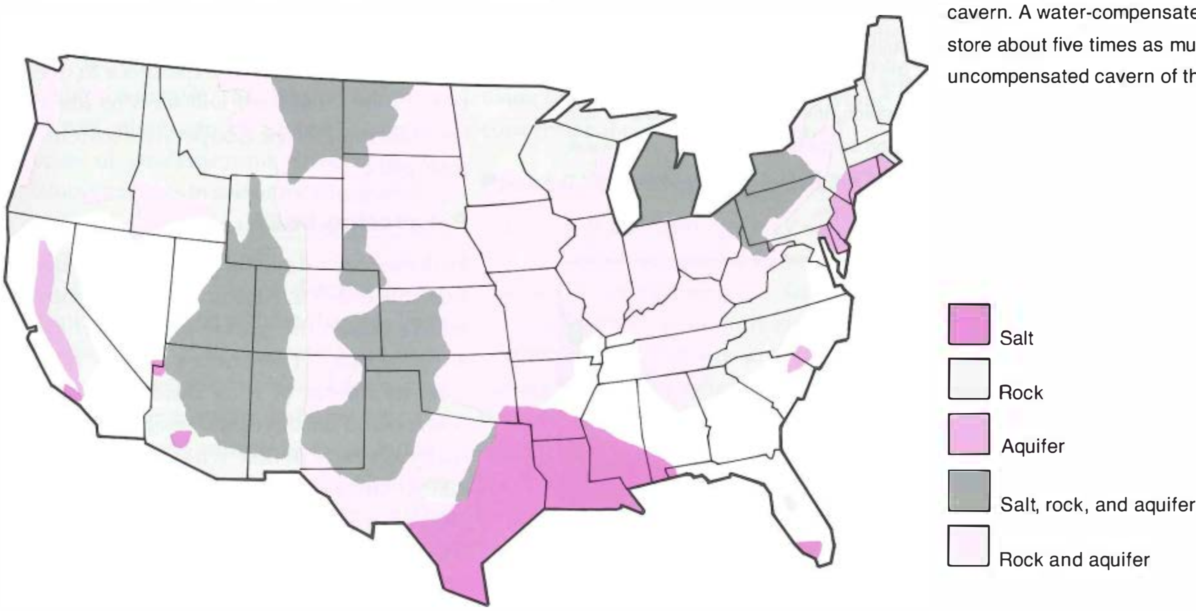




Salt Of the three storage media, salt caverns are probably the most thoroughly understood. The CAES plant in Huntorf, West Germany, uses salt storage, and here in the United States salt caverns are used extensively to store natural gas, propane, and strategic petroleum reserves. To develop a salt cavern for a CAES plant, fresh water is injected into a well to dissolve the salt; the brine is then pumped out, leaving an airtight cavity. Salt caverns operate at a constant volume and variable pressure. Because the pressure diminishes as the air is removed, a large cavern is required.

Aquifers Long used for the seasonal storage of natural gas, aquifers are the least expensive formations to develop. Fractured rock or porous sandstone under a layer of impervious caprock provides space for the compressed air. Wells are drilled through the caprock to inject air into the space and displace water, which confines the air and provides pressure to force it to the surface during the generation cycle. Aquifers that would be used for CAES plants are not used for drinking water or irrigation; they lie deeper than freshwater aquifers and contain brine.

Rock Hard-rock caverns are currently used to store hydrocarbon fuels and are potentially the most abundant storage media in the United States. Carving a cavern out of hard rock is more expensive than developing a salt or aquifer reservoir. For this reason, it is desirable to keep the cavern small and maintain the stored air at a constant pressure by means of a water compensation system. A vertical shaft connects the underground chamber with a surface lake. As air is injected into the cavern, the column of water is pushed up; as air is released, the water fills the vacated space in the cavern. A water-compensated rock cavern can store about five times as much energy as an uncompensated cavern of the same volume.



units, a combustion turbine, and purchased power make up the balance. With a generating mix dominated by coal units, providing baseload power isn't an immediate problem. The utility's pressing need is for peaking and intermediate power, especially during hot southern summers, when thousands of air conditioners soak up kilowatts. Some of the coal units have been modified for load following, but such cyclic, "slow-and-go" operation—like city driving—makes for poor fuel economy and increases wear and tear on key components. Though it is more economical to run baseload units at a more constant load, AEC has had no way to use the surplus power produced during periods of reduced demand.

In analyzing its needs, the utility saw that it clearly had to narrow the gap between its peak and off-peak capacity in order to respond efficiently to the daily swings of electricity demand. The co-op evaluated a number of options for adding peak and intermediate capacity, including simple-cycle combustion turbines, combined-cycle turbines, pumped-hydro storage, and CAES. As it turned out, Alabama Electric Cooperative's need for additional peaking and intermediate capacity dovetailed with EPRI's search for a utility willing to build and operate the country's first commercial CAES plant.

"Our planning people looked at all the options, and CAES came out on top from a strictly economic standpoint," says John Howard, AEC's division manager of power production and construction. "We didn't make the decision so we could be the first to build a CAES plant in the United States; the decision was based on the fact that CAES best fits our needs at this point in time. It was the most economical generation source that we saw out there. The capital costs are higher than those for a straight gas turbine, but the operating costs are considerably lower."

AEC's evaluation also revealed that its service area encompassed a geological formation well-suited to storing air under pressure. The McIntosh salt dome—a remnant of an evaporated ancient sea that migrated upward to near the earth's surface—is an underground mountain of essentially pure sodium chloride measuring a mile in diameter and extending some 40,000 feet into the earth. Olin Chemical Corp. operates a large chlor-alkali plant in the area and was willing to lease Alabama Electric a 40-acre parcel of land for the first (and potentially a second) CAES plant. The utility and the chemical company drafted a plan by which Olin would supply water for solution-mining the cavern, a process that involves pumping in fresh water to dissolve the salt, with the resultant brine piped to the chemical plant as feedstock to produce sodium, chlorine, hydrogen, and caustic soda. The fact that Olin wanted to accept the brine facilitated the process of gaining the necessary environmental approvals to begin construction.

With EPRI's assistance, Alabama Electric Cooperative prepared detailed specifications for the plant and solicited bids from several U.S. architect-engineers. In early 1988, the turnkey contract for a 110-MW plant with 26 hours of storage was awarded to a joint venture of Harbert International and Gibbs & Hill, with Dresser-Rand serving as the turbomachinery subcontractor and Fenix & Scisson as the cavern subcontractor. The final contract was signed in August. The total value of the contract, in current dollars, is $50.9 million ($463/kW).

EPRI has committed $6.9 million to the project. The Institute is providing funds toward the plant recuperator, technical assistance, and an engineer of record, who will document the events that led to AEC's decision to build the plant, the engineering and construction experience, and two years' worth of operational data. EPRI funding will also pay for scientific instruments used to monitor plant performance, and an information storage and retrieval system to archive and provide access to the data.

The McIntosh plant will differ from the Huntorf facility in several ways. Most important, it will be the first CAES facility to use an exhaust stack recuperator, or heat exchanger, which raises the temperature of the stored air from about 95°F to 547°F before it enters the combustor. This EPRI-designed component is expected to reduce fuel consumption by approximately 27%. AEC's plant is also being built with dual-fuel burners to allow it to run on distillate fuel oil as well as natural gas. Another difference is the volume of the reservoir. AEC's 19-million-cubic-foot cavern will allow the plant to generate at 110-MW capacity for a full 26 hours. Huntorf, in contrast, generates for about four hours on a fully charged 10.6-million-cubic-foot, two-cavern system. "We found it extraordinarily inexpensive to provide extra hours of storage," says Schainker. "This plant will cost on the order of 70¢ per kilowatt for each extra hour of storage. In comparison, a lead-acid battery costs around $200 per kilowatt for each extra hour of storage."

AEC's economic studies also showed that a larger cavern would make it possible for compression to be done over the weekend, when electricity is cheapest, as well as every night. During a typical week of operation, the plant will generate for about 10 hours each weekday and partially recharge the cavern every night; over the weekend the cavern will be fully recharged in about 35 hours. The AEC plant will require about 1.7 hours of compression for every hour of generation. The Huntorf plant has a four-to-one compression-to-generation ratio.

Schainker points out that by varying the cavern volume and the compression ratio, a CAES plant can be matched to the specific needs of a particular utility. "Compressed-air storage—unlike any other storage technology—allows a utility to tailor both the size of the compressor and the size of the expander to that utility's load curve," he says. This point is especially significant for the utility industry.

Electricity demand fluctuates according to daily and seasonal cycles that are specific to a given utility's service area. A CAES system can be designed to operate not only on a daily or weekly cycle, but on a seasonal cycle as well, if the reservoir is sized appropriately. For aquifer-based plants, this option is especially cost-attractive, notes Schainker.

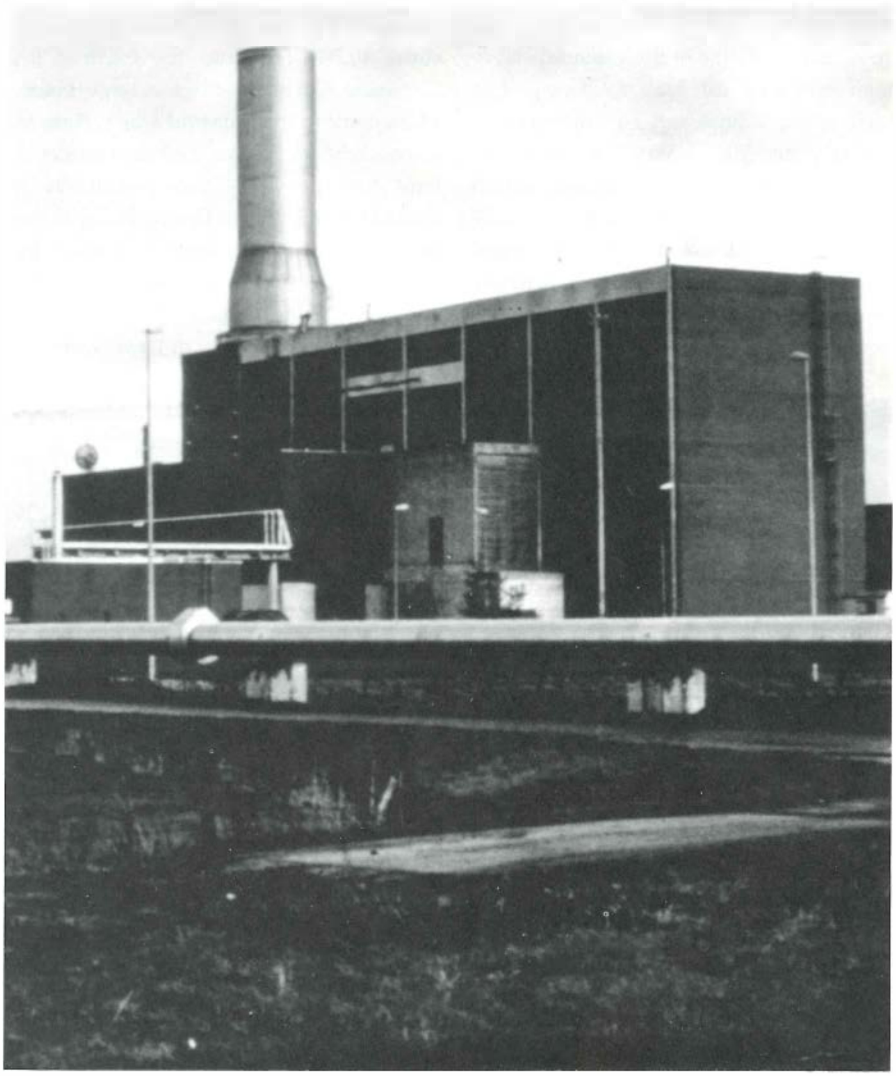
Building confidence

Despite its economic benefits and proven performance, CAES has been slow to catch on. A major reason is that underground storage technology is alien to most utilities. "The electric utility industry in general does not store anything underground, and it may be hesitant because it is not familiar with designing, building, and operating these systems," says Bhupen (Ben) Mehta, a project manager in the Energy Storage Program. "Mother Earth has been explored for many years, and the technical aspects of underground storage are well established." Mehta emphasizes that the petroleum and natural gas industries have stored liquid and gaseous hydrocarbon fuels in underground reservoirs for some 70 years, and this vast body of experience is directly applicable to the storage of compressed air for CAES plants. Since 1915, natural gas companies have operated more than 400 underground storage reservoirs in aquifers, depleted gas and oil fields, and solution-mined salt caverns in 26 states, with a total capacity of 7.7 trillion cubic feet. The total underground storage capacity in rock and salt caverns for storing liquid hydrocarbons, strategic petroleum reserves, liquefied petroleum gas, and gasoline is more than 1000 million barrels.

Another reason behind the slow acceptance of CAES is that utility planners rely on readily quantifiable costs and benefits when evaluating a new plant. Existing cost models, however, are designed for generation-based technologies and do not quantify all the benefits directly associated with the operation of a storage

A Successful CAES History

The world's first CAES plant, in Huntorf, West Germany, has operated for more than a decade, demonstrating excellent availability and starting reliability. While fundamentally similar to Huntorf, the McIntosh plant will be the first CAES unit with an exhaust heat recuperator and a dual-fuel capability.



Parameter	Huntorf	McIntosh
Output (MW)	290	110
Hours of storage	4	26
Charge-discharge ratio	4 to 1	1.7 to 1
Energy ratio (kWh in/out)	0.83	0.82
Heat rate (Btu/kWh)	5500	4100
Recuperator	No	Yes
Fuel	Gas	Oil or gas
Number of caverns	2	1
Total cavern volume (million ft^3)	10.6	19

plant. "The generation-based tools neglect the dynamic benefits of energy storage," says Schainker. "These are the benefits that accrue to a utility system's overall operation by virtue of a storage plant's fast response rate, quick startup and shutdown, and high part-load efficiency." A CAES unit's ramp rate—its ability to raise or lower its power output—is about 33% of its nameplate rating per minute. Thus a 100-MW CAES plant can change its load at a rate of 33 MW per minute, much faster than any fossil fuel unit. Using a CAES plant for load following and spinning reserve can minimize the inefficient use of thermal plants for these duties. The dynamic benefits of storage are getting more attention at EPRI and utilities, and are proving in some cases to be equal to the cost savings achieved by load leveling alone.

EPRI is developing a computer model called DYNASTORE that quantifies the dynamic benefits of energy storage to help utilities improve planning decisions. The model simulates a 24-hour period in 10-minute time steps, permitting an accurate evaluation of high-ramp-rate storage plants. A case study performed with DYNASTORE revealed that energy storage could achieve significant savings. For example, spinning-reserve and load-following benefits accounted for about 48% of daily fuel cost savings; this savings is equivalent to $300/kW in capital cost savings.

Gaining momentum

As a further indication that the technology has finally come into its own, several other nations are building or contemplating CAES plants. The Soviet Union is planning to build a 1050-MW plant in the Donbass region north of the Black Sea that will use three turbomachinery units and nine salt caverns. The Italian utility ENEL has built a 25-MW CAES research facility that uses aquifer storage, and Israel recently announced plans to build three 100-MW CAES units using a fractured-rock aquifer.

Closer to home, several U.S. utilities are conducting detailed geology and/or feasibility studies. With assistance from EPRI, the Sacramento Municipal Utility District is investigating a depleted natural gas field in northern California as a potential CAES site. Also, Duke Power is looking at hard-rock storage facilities in its service area.

Schainker's project team is looking ahead to CAES's future, evaluating refinements to improve the technology's efficiency and flexibility. One option, "which looks attractive on paper," says Bob Pollak, EPRI's project manager for the AEC plant, involves putting to work some of the heat generated during the compression cycle, which in current designs is rejected into the atmosphere. The compression heat could be captured in a thermal energy storage (TES) system and saved for use during the generation cycle. In one approach, the stored heat would be used to boost the temperature of the air entering the expansion turbine, reducing the amounts of premium fuels burned and their associated emissions. An alternative TES scheme would use the stored compression heat to generate steam, which would be added to the compressed air being injected into the turbine. "Ultimately, if you take thermal energy storage to the theoretical limit," says Pollak, "you can build an adiabatic—no heat loss—CAES plant, which would require no fuel at all. You would have electricity going in for compression, and electricity coming out of the expander, with the efficiency of the plant somewhere around 65%. That's one of our goals."

Other potentially attractive CAES cycles are also under investigation, such as using exhaust heat to generate steam for injection into the turbine or for use in a separate steam turbine. EPRI is also studying the feasibility of using advanced coal-burning technologies, such as fluidized-bed combustion and gasification-combined cycles, in a CAES plant.

The future of such advanced-cycle systems will of course depend on the success of AEC's plant, which is the main objective of EPRI's CAES projects. To assist utilities interested in the technology, the Institute has established a CAES working group, whose members include representatives from 45 utilities. Through briefings, site tours, and reports from the engineer of record, group members will monitor the progress of the AEC plant and provide their utilities with comprehensive cost and design information that planners can use in evaluating the CAES option for their own generating mix. As the McIntosh plant establishes CAES's foothold in the United States, other utilities will be able to witness firsthand the benefits of the technology and gain the confidence to proceed from an attitude of "Let's wait and see" to "Let's find out if we can do it too." ■

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This article was written by David Boutacoff. Technical background information was provided by James Birk, Robert Schainker, Ben Mehta, and Robert Pollak, Generation and Storage Division.

TECH TRANSFER NEWS

Pretreatments Improve PWR Radwaste Processing

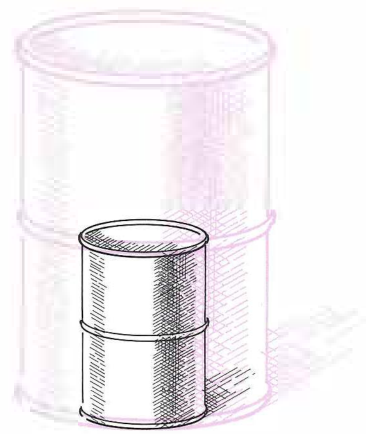
Low-level radioactive wastewater (radwaste) from pressurized water reactors must be processed to remove radioactive substances before it can be released to the environment or recycled. The cost of removing these contaminants can be high, often exceeding $1 million to $2 million per year for a typical PWR. In recent years, many utilities processing PWR radwaste have converted from evaporation systems to ion-exchange systems, which are simpler to operate and more cost-effective.

There have been some problems with these systems, however. For example, Duke Power found that waste volumes and effluent radionuclide concentrations in its nonrecyclable liquid radwaste were higher than anticipated. At one plant, the new ion-exchange system was so unreliable that Duke considered returning to evaporation systems.

In response to these problems, Duke joined EPRI in an exploratory study to identify techniques that would improve the effectiveness of ion-exchange systems. The research indicates that waste pretreatment and the use of better resin bed materials are the best methods for improving system reliability. After a series of bench-scale and in-plant tests and the screening of 34 pretreatment agents and more than 70 bed materials, Duke adopted the new techniques at its Oconee and McGuire plants.

Routinely at Oconee and periodically at McGuire, Duke now pretreats liquid radwaste with coagulating salts and/or polyelectrolytes to improve radionuclide removal; it also uses optimized ratios of strong acid and strong base ion-exchange resins. With the coagulating pretreatments, the resin beds act as colloid filters while simultaneously providing ion exchange. High ratios of cation to anion exchange resins extend the beds' service life. As a result, Duke reduced critical effluent radionuclide concentrations by 90%, ion-exchange waste volumes by 65%, and processing costs by 50%.

Duke estimates $6 million in savings from 1986 to 1988 as a result of the reductions in radionuclide concentrations and waste volumes achieved with the removal processes. The improved reliability afforded by the new techniques allowed Duke to cancel costly plant modification plans. "At one time, we doubted that ion exchange was reliable enough to meet our radwaste treatment needs,"



says Duke research engineer Russell Propst. "But after trying the techniques developed through this research, we consider ion exchange the process of choice for nonrecyclable waste."

Utilities can use some of the techniques developed by Duke and EPRI without equipment modification. Pacific Gas and Electric, Southern California Edison, and Duke (at its Catawba plant) have made successful applications. Other removal techniques may require further development and system modification before use. All the techniques are described in a report prepared by EPRI and Duke, *Pretreatments and Selective Materials for Improved Processing of PWR Liquid Radioactive Wastes* (NP-5786). ■ *EPRI Contact: Patricia Robinson, (415) 855-2412*

Product Books Ease Access to R&D

Over the past several years, EPRI has increasingly focused on technology transfer as essential to its overall mission. One aspect of that focus has been the development of a series of books called *EPRI Products.* Designed to enhance the technology transfer process, this proprietary eight-volume series takes information from thousands of technical reports and packages it in a form that is easily referenced, evaluated, and put to use by personnel at member utilities.

"We developed the product books to solve two important problems for our member utilities," says Ed Beardsworth, a member of EPRI's Research Applications staff. "One was to be able to assess the past benefits of EPRI membership. The other was to make potential users aware of existing results that could help them in the future, and make it possible for them to judge quickly what deserved more of their time and attention."

The key to meeting these goals was development of the concept of the R&D product. A product may consist of a single technical report, such as a handbook, or it may encompass information found in dozens of reports. To qualify as a product, a body of information must provide a solution to a generic industry problem or opportunity; have identifiable benefits associated with its use by a member utility; and be available for immediate application. The current product book series contains more than 800 products. These include hardware, process technology, computer software, test methodologies, how-to manuals, design guidelines, diagnostic techniques, data bases, state-of-the-art assessments, and scientific findings.

Each product book is dedicated to a general subject area, a format that allows most users to meet their needs with one or two volumes. Products applicable to more than one area are included in all the appropriate books. The current series consists of these volumes: (1) Utilization, (2) Environment, (3) Fossil Power Plants, (4) Nuclear Power Plants, (5) Environmental Control Technology, (6) Advanced, Renewable, and Storage Systems, (7) Delivery, and (8) Planning.

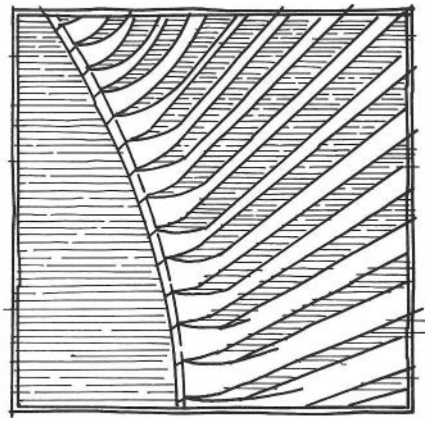
Each volume contains 100-200 product sheets detailing product use, benefits, and successful applications. Products are grouped around special issues or such specific problem areas as heat rate improvement, transmission line design, and occupational radiation management. This format helps line managers think in broad terms about how EPRI R&D results can match their objectives, and it offers senior managers a clearer picture of how EPRI supports their company goals.

Intended to serve as a tool for building a systematic, ongoing process for technology transfer, the product book series is more than a catalog. The product format helps technology transfer coordinators at member utilities to direct information to those who can use it and to obtain feedback on the results. Moreover, it provides a framework for benefits assessment activities to help members gauge and improve the return on their investment in EPRI.

"In the past," Beardsworth notes, "we often relied on the traditional R&D 'better mousetrap' idea—that all we had to do was produce good science and technology, and people who needed the answers would dig them out of the reports and journals by themselves, and manufacturers and vendors would come looking for our licensable items. But we've realized that we have to make sure the work is being packaged in ways accessible to our clients, so they can find what they need to know when they need it—or better yet, even before they know they need it." ■ *EPRI Contact: Ed Beardsworth, (415) 855-2740*

Coating Reduces Erosion of Steam Turbine Blades

Solid-particle erosion of large utility steam turbine generators costs ratepayers more than $150 million annually in reduced thermal efficiency, lowered generating capacity, and increased plant downtime. To help minimize erosion damage, EPRI funded the development of a chromium carbide plasma coating for steam turbine rotating and stationary blading. Developed by General Electric, the coating has an erosion rate 10 times



less than that of conventional steam turbine blade materials—uncoated Type 422 (12% chrome, martensitic) stainless steel.

The coating is applied to critical steam path components with advanced, robotically controlled plasma spray processing systems. This ensures coating quality and limits substrate temperatures to less than 500°F during the process. The low application temperature and uniform coverage ensure that the coating process does not affect substrate metallurgical properties and dimensions.

The coating is commercially available from General Electric and from Sermatech International. ■ *EPRI Contact: Tom McCloskey, (415) 855-2655; General Electric Contact: John Reiley, (415) 726-7327; Sermatech Contact: Thomas Lewis, (315) 582-6080*

Early Detection of Induction Motor Problems

Utilities can now detect defective rotors in induction motors before failure, and they can do so while a motor is running and under load, without installing any special apparatus. The EPRI-developed broken-bar detector is a diagnostic tool that reliably detects defective open-circuited rotor bars and cracked end rings. Capable of detecting a single broken bar without previous measurements, the suitcase-sized device consists of a filter, an analog-to-digital conversion unit, and software residing in a portable computer. The device performs a broken-bar diagnosis based on an examination of the current frequency spectrum, monitoring both line current and leakage flux emanating from the end of the machine.

The new detector represents a breakthrough for utilities because it is sensitive enough to detect the first broken bar and can be used on an operating motor. Devices like the "growler" and other conventional probe techniques can be applied only to disassembled motors, and single-phase testing can be performed only on nonoperating assembled motors.

Six utilities have field-tested the device, which is available from General Electric. ■ *EPRI Contact: Jan Stein, (415) 855-2390; General Electric Contact: M. Rao, (518) 385-3564*

Community-Based Health Studies

Indoor/Outdoor Air Quality and Human Health

by Cary Young, Environment Division

ABSTRACT *Research on the health effects of air pollution has traditionally focused on the quality of outdoor air. It has become evident, however, that indoor environments can also be important in determining pollutant exposure levels. Two community health studies being cosponsored by EPRI are taking into account both indoor and outdoor air quality. One, the Harvard Six Cities Study, is a longitudinal investigation of possible respiratory health effects in the general population from chronic low-level exposure to certain substances. The other, the Tucson Community Study, focuses on short-term effects in subjects considered to be especially sensitive to air pollutants. The results of these studies will be valuable in formulating adequate, cost-effective air pollution control strategies.*

The quality of the air we breathe has been an environmental health concern of the public and the scientific community at least since the first half of this century, when there were several episodes of extreme air pollution in highly industrialized and urbanized locations. Studies of these episodes and subsequent studies demonstrated excesses in respiratory disease and mortality in populations exposed to mixtures of sulfur oxides, nitrogen oxides, and particulate matter. In the United States, the Clean Air Act Amendments of 1970 resulted in the establishment of specific ambient air quality standards to protect the public's health from this type of pollution.

Research on the health effects of outdoor air quality continues today, as it addresses the challenges of studying much lower levels of pollution and refining the measures of both exposures and health outcomes. Moreover, concern about the possible health risks of air pollution has expanded in recent years to include indoor air quality. It is becoming increasingly evident that indoor environments play a critical role in determining the actual pollutant exposures of individuals. We now recognize that there are a number of indoor sources for some of the same pollutants measured in outdoor air, as well as for other pollutants that might cause a particular health outcome of interest. Also, we now know that levels of many pollutants are often higher inside buildings, where people generally spend a majority of their time, than outside. Reducing the ventilation of buildings for energy conservation, which can cause the levels of potentially harmful pollutants to build up indoors, is a factor that further complicates the picture.

In short, a new way of thinking about the health consequences of air pollution is required—one that pays careful attention to both indoor and outdoor air quality. Two ongoing EPRI-supported community-based health studies demonstrate the importance and application of this new way of thinking: the Harvard Six Cities Study and the Tucson Community Study of Indoor and Outdoor Air Pollution.

Six Cities Study

Conducted by the Harvard School of Public Health and cofunded primarily by the National Institute of Environmental Health Sciences and EPRI, the Six Cities Study began in 1974 as a prospective investigation of the respiratory health of residents in six communities in the eastern and midwestern United States.

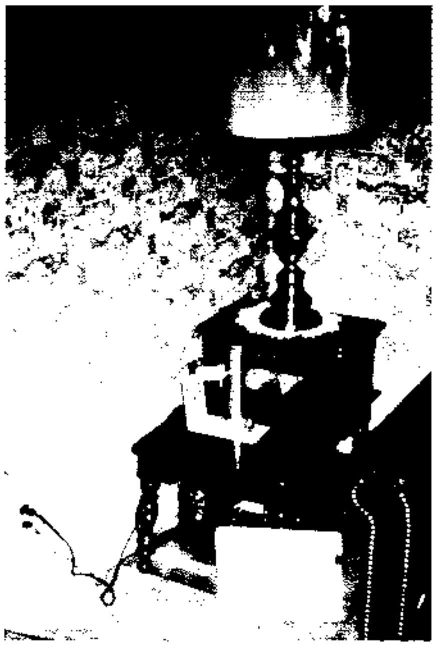
The study was originally designed to estimate to what degree respiratory disease is caused by chronic exposure to urban atmospheres contaminated by fossil fuel combustion products. Its basic design involves state-of-the-art air pollution monitoring and long-term follow-up of school children and adults in each of the six cities. Periodic physiological and questionnaire examinations (annually for children and triennially for adults) are administered, in a standardized way, to measure lung function, respiratory illness, and such respiratory symptoms as persistent cough and wheeze. Definitive longitudinal analyses will be performed after the completion of data collection, which is scheduled for early 1989. The results of an initial analysis done across the cities for the earliest years of the study have been reported (*EPRI Journal,* December 1986, p. 52).

Early on, it became clear to the Harvard researchers that a more complete understanding of air pollution exposure would require accounting for contaminated indoor environments. They knew that certain pollutants measured in ambient outdoor air could have emission sources indoors. Moreover, previous studies indicated that exposure to some of these indoor sources, particularly tobacco smoking, might influence respiratory health in childhood. In fact, when data from the first annual examinations of participating children in the Six Cities Study were reviewed, they showed that children 6 to 10 years of age living with cigarette-smoking parents had more respiratory illness and impairment of lung function than children living with nonsmokers. The data also suggested that the use of gas stoves for cooking was associated with slight impairment of lung function in children, although not with illness and symptom rates.

To pursue these findings further and to obtain more information that would help minimize the chance of mixing—in the final analysis phase—the health effects attributable to outdoor air pollution with those due to indoor air pollution, the investigators launched a specific substudy of the indoor environment.

The air-monitoring component of this indoor study focuses on nitrogen dioxide (NO_2) and respirable-size particulate matter (fine particles), since initial measurements revealed that elevated levels of NO_2 occur in homes with gas cooking stoves and that levels of fine particles are on average higher in the homes of cigarette smokers than in the homes of nonsmokers. In each city 300 homes are being monitored twice, once in the winter and again in the summer Complete monitoring instrumentation (Figure 1) is placed in the room where the child spends the most waking hours (called the activity room); other NO_2-monitoring locations are the kitchen and the child's bedroom. A detailed home characterization questionnaire is being used to better define exposure to passive smoking, gas stoves, and other features of the indoor environment (e.g., woodstoves, unvented kerosene heaters, and molds, mildew, and water damage).

Figure 1 Air-monitoring instruments. Fine particles are collected by drawing air through an impactor (tall device on table) with a quiet, compact pumping system (under table). NO_2 is monitored passively by means of a specially designed diffusion tube. Other tubes collect tracer gases used to measure the home's air exchange rate.



The health data collection effort entails a year-long survey of respiratory symptoms exhibited by the study children residing in each monitored home. The children's parents maintain a log of symptom occurrence, duration, and intensity.

Analyses of the association between indoor exposures and symptoms are scheduled for completion in 1990. In the meantime, the indoor measurements have already been analyzed to identify predictors of indoor levels of NO_2 and fine particles, and methods for estimating personal exposures have been established. This information will be used later. along with that derived from outdoor measurements, to assess the overall long-term effects of exposure to air pollution from indoor and outdoor sources on respiratory disease.

Tucson Community Study

The Tucson Community Study of Indoor and Outdoor Air Pollution, begun in 1987 by investigators at the University of Arizona School of Medicine, takes a different approach to evaluating the respiratory health effects of air pollution. This study focuses on short-term changes in the respiratory responses of adults and children in selected households and on possible correlations between these changes and total (indoor and outdoor) exposures. It is jointly sponsored by the Environmental Protection Agency and EPRI.

The researchers are using a multistage design to address various questions about day-to-day variation in respiratory symptoms, lung function, and other health outcomes that may be caused by combustion pollutants, formaldehyde, and particulate matter. To date, more than 200 households have completed the second stage of the study, which entails a two-week sampling period. During this period, a detailed questionnaire on home characteristics and occupant behaviors is completed, and air pollution levels inside and outside the home are monitored intensively. In addition, each participating occupant reports his or her respiratory symptoms in a diary and performs a simple lung function test up to four times daily. The lung function measurements are used to identify individuals demonstrating excessive variability, which is believed to be an indicator of the sensitivity of the respiratory tract to environmental stimuli. Those individuals deemed sensitive will go on to the third stage of the study, when a more in-depth evaluation of exposures and responses will be conducted.

The frequency of excessive variability in lung function has already been compared with some of the measured pollutant levels and with reported cigarette smoking in the home. Preliminary analysis shows that children under the age of 15 had the largest range of variability, and that their rates of excessive variability were positively associated with passive smoking and with formaldehyde. The investigators did not find any association between indoor NO_2 levels (based on week-long averages) and either lung function variability or the rates of reported symptoms.

Research benefits

The two studies just described are examples of research carried out in natural settings to advance our understanding of the health effects of air pollution. These studies differ in several ways: one seeks to uncover any long-term effects by evaluating responses in groups of the general population against indicators of chronic low-level exposure; the other is geared toward identifying short-term effects and making direct links with exposure in individual subjects who may be the most sensitive to air pollutants. More critical than the studies' differences, however, is their similarity in considering both indoor and outdoor environments.

Perhaps the most important potential benefit of this comprehensive approach is that the relative contributions of indoor and outdoor air quality to health risks can be placed in perspective. This knowledge, in turn, can improve the basis for future policy decisions on adequate and cost-effective air pollution control strategies to safeguard human health. Such decisions, which involve judgments about how best to allocate resources to control indoor and outdoor sources, could have significant impact on the operations of electric utilities.

Nuclear Component Reliability

Nondestructive Evaluation of Turbine Disks

by Soung-Nan Liu, Nuclear Power Division

ABSTRACT *Stress corrosion cracking in the shrunk-on disks of low-pressure steam turbine rotor shafts has been a major concern in the United States for almost a decade. First discovered in nuclear power plants and more recently in fossil fuel plants, the cracking has become more frequent as the average age of operating units has increased. To ensure disk integrity and to avoid forced plant outages due to disk failures, EPRI is developing a reliable method for nondestructive evaluation.*

Rotor shafts forged from single ingots are used for high- and intermediate-pressure turbines in U.S. power plants. Because of their physical size, however, rotor shafts for low-pressure (LP) turbines are often forged with a series of diameters along the length, and separately forged disks are thermally shrunk onto the shaft. The disks are shrunk on in sequence, and keyways are drilled in the shaft step and inner bore of the disk. A metal pin, or key, is then inserted in the keyway. The number of keys per disk varies, as does the shape of the keyways. These keyways are used to keep the disk from rotating on the rotor shaft during a transient or in the event of an overspeed incident.

Stress corrosion cracking

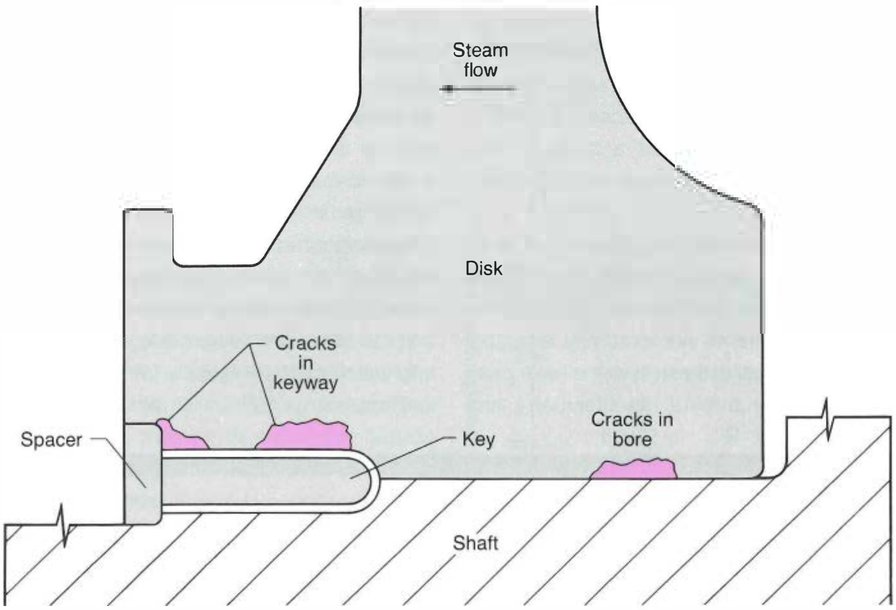
Service-induced stress corrosion cracking has been found near keyway and bore regions in many LP turbines with shrunk-on disks (Figure 1). The root cause of stress corrosion cracking has not been uniquely defined, since crack growth will progress in pure water as well as in caustic chloride solutions and concentrated sodium hydroxide solutions. However, it is known that keyways are subject to very high stresses and that corrodents can build up as steam condenses in the stagnant region of the keyways—conditions conducive to stress corrosion cracking.

In 1969 a catastrophic failure of the Hinkley Point A low-pressure steam turbine in England occurred because of stress corrosion in one of the disk keyways. The Hinkley Point failure brought into sharp focus the necessity for reliable examination of shrunk-on LP disks. More recently cracking has been confirmed in shrunk-on disks of many LP turbines at nuclear and fossil power plants in the United States.

State-of-the-art NDE

Nuclear power plant turbines may be available for nondestructive evaluation (NDE) during normal refueling outages (approximately 18-month intervals). However, utilities would like to extend the inspection interval to

Figure 1 This cross section of a low-pressure turbine rotor shaft shows areas of a shrunk-on disk that are especially prone to service-induced stress corrosion cracking. EPRI is sponsoring research to develop a fully automated ultrasonic testing system for in situ disk inspection.



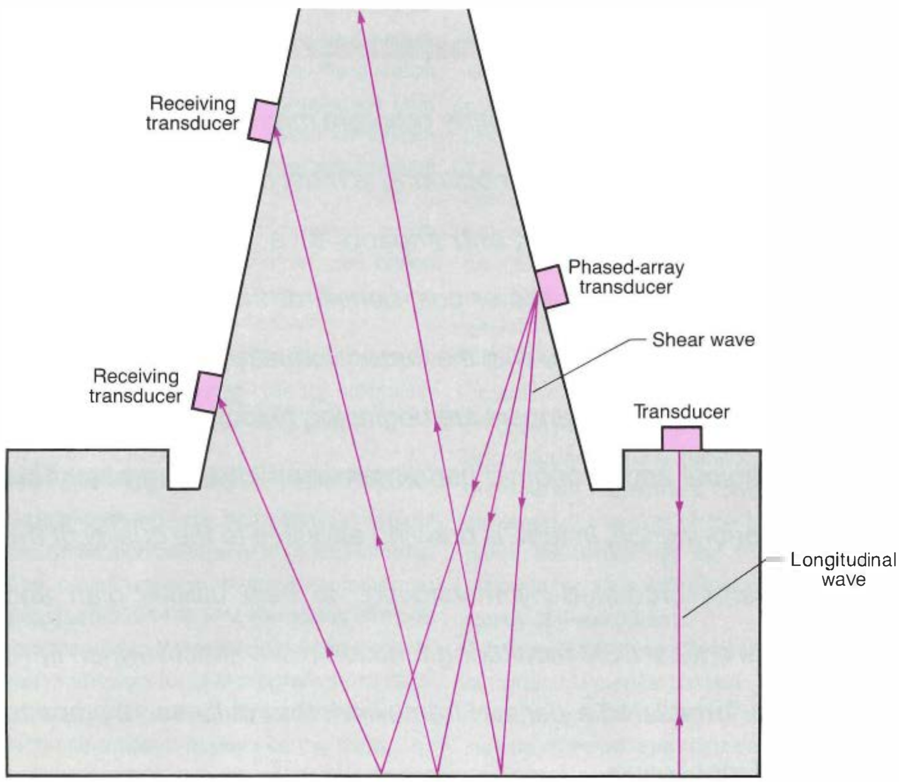


Figure 2 Both shear (pitch-catch mode) and longitudinal ultrasonic waves are used to ensure complete coverage of the disk inspection area.

match major overhaul periods, which occur approximately every five years. At this time the upper half of the LP turbine case is removed to permit inspection of the disks or blades in situ. In some cases the complete turbine assembly is removed to accommodate other maintenance requirements and is placed on a motorized roller for examination. Even though fuel replacement takes several weeks, the inspection must be accomplished in considerably less time to allow for scheduling and to provide time for corrective action should unacceptable cracks be found. Before inspection the disk surfaces are cleaned to remove loose scale, rust, grease, and other materials. Excessive debris produced during the cleaning process with the turbine in situ may be detrimental to subsequent operation. Caution should be exercised in determining whether the disk needs to be inspected in situ or placed on a motorized rotor.

The most commonly used NDE method for volumetric examination of turbine disks is ultrasonic testing (UT). Flaw detection is accomplished by looking for either the direct reflection off the side of a crack or the corner reflection from a crack and the bore. Where geometry permits, a 0-degree, longitudinal-wave ultrasonic transducer is used. Most disk inspection, however, is performed with shear-wave transducers.

The ultrasonic beam path of transmitting and receiving transducers (in pitch-catch mode) can be calculated to ensure adequate coverage of the desired inspection region (Figure 2). To maximize the flaw detection sensitivity, the beam angle is chosen for each disk so that the ultrasonic beam strikes the keyway in a nearly tangential direction. The detection and sizing of defects are often determined by the relative echo amplitude off a crack and the keyway. Unexpectedly high amplitude echo responses can result from pitting or scoring marks introduced during assembly and can be mistakenly recorded as defects. To date, insufficient data and experience have made reliable distinctions between flaws and geometric features difficult. Current techniques are also incapable of sizing detected flaws solely on the basis of signal amplitudes.

Developing an automatic system

The currently available UT techniques for turbine disk inspection can be grouped into three categories according to their operating modes:

- Manual scanning and manual data recording (manual system)
- Manual scanning and automated data recording (semiautomatic system)
- Automatic scanning and automated data recording (automatic system)

With manual-scanning approaches, it is difficult to trace the precise path of ultrasonic beams; as a result, flaw detection and characterization can be ambiguous. Furthermore, because of the operator-dependent nature of such systems and the spatial constraints between disks, repeatable inspection may not always be possible. The clearance between disks for certain stages of turbine assemblies can be as small as 2 inches or smaller. Therefore, for inspecting such a complex component as a turbine disk, the use of an automatic system is highly recommended.

In 1987 EPRI conducted a survey of state-of-the-art UT technology for turbine disk inspection. The results showed that only a few automatic systems are currently available worldwide. Most of these systems have been developed by turbine manufacturers and service organizations abroad, and are either proprietary or applicable only to a specific turbine disk design.

To provide utilities with access to advanced UT technology, EPRI recently initiated a project to develop an advanced mechanized scanner and controller (RP2857). The scanner is intended for turbine disks manufactured by General Electric and Westinghouse. The 18-month project, scheduled for completion in 1990, will be integrated with advanced UT technology developed under other EPRI contracts (RP1803-5, RP2165-3, and RPT301-1) and will provide utilities with a fully automated UT system for turbine disk inspection.

Demand-Side Planning and Information

DSM Program Monitoring

by William M. Smith and Steven D. Braithwait, Customer Systems Division

ABSTRACT *According to utility program managers, demand-side management (DSM) program monitoring is most often used to demonstrate a program's progress and impacts to a regulatory body, to assess the cost-effectiveness or cost-benefit of the program, and to modify an existing program. With the current industry emphasis on cost competitiveness, utility planners are beginning to focus more attention on the technical and economic performance of DSM programs. This focus on performance, in turn, is drawing attention to the quality of the measurements produced by monitoring. To help utilities plan and conduct the critical DSM monitoring function more effectively, an EPRI project has formulated a general framework that outlines 12 steps to successful monitoring.*

As utility interest in incorporating demand-side alternatives into the resource planning process grows, reliable information on the cost and performance of a wide range of DSM program options becomes crucial. The usefulness of demand- and supply-side resource comparisons depends heavily on the validity of the assumed values of program cost, acceptance, and load impacts. A range of sources of data on these values is available; however, for programs currently in place, the accurate measurement and evaluation of a utility's own program impacts is likely to be the most reliable. If DSM program performance continues to attract utility and regulatory interest, more resources will probably be devoted to the monitoring function of the overall DSM process.

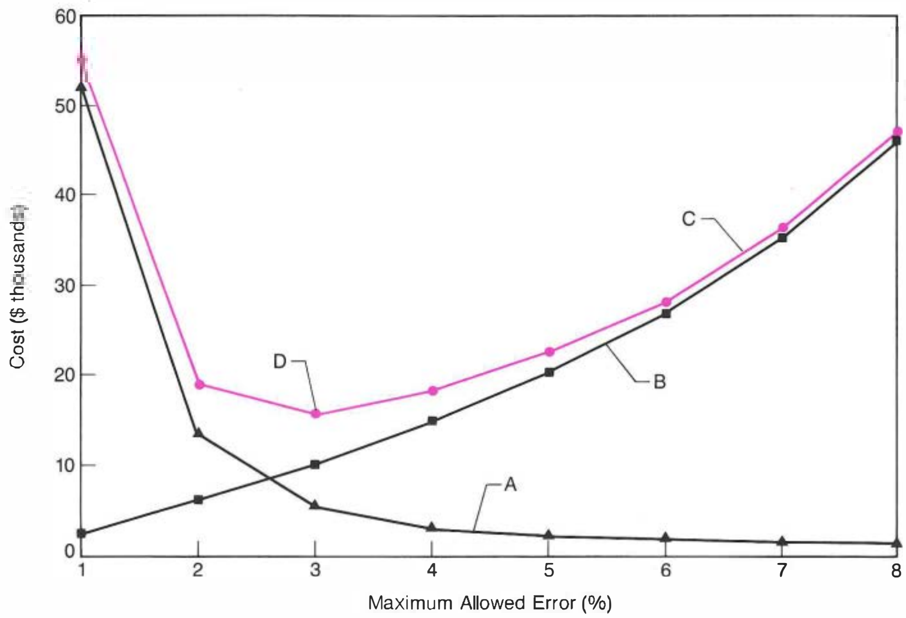
DSM program monitoring is defined as the process of measuring the performance of a program, including its cost, participation rates, incremental load impacts, and overall effectiveness. Two broad types of approaches to monitoring—descriptive and experimental—have been described in the

DSM literature. The first consists of descriptions of a program's activities and results. Examples include documentation of program costs, activities completed, participation rates, and the characteristics of equipment installed. The descriptive approach can be applied to both mature and developmental programs.

Experimental approaches use techniques common to hypothesis testing. They permit the analyst to distinguish between outcomes occurring as a result of the program and those that probably would have occurred anyway. Program results are those actually achieved by the utility's investment in the program. Experimental monitoring designs typically require the use of either comparison groups or reliable historical data on normal outcomes under typical circumstances. This approach, therefore, typically costs more to conduct than descriptive monitoring. Consequently, the use of comparison groups or historical data is usually associated with small-scale developmental programs in which the principal objective is to develop information on what a mature program might accomplish. This information then influences the decision on whether to invest in a larger-scale DSM program. Examples of analyses sometimes associated with experimental approaches include:

- The determination of comparison group and experimental group sample sizes, based on considerations of required accuracy and confidence levels
- The consideration of costs versus errors in collecting and analyzing data for estimating participation (enrollment) rates (Figure 1)

Figure 1 A graph that shows costs at various levels of allowed error in estimating the enrollment rate for a DSM program can serve as an aid to decision making on program monitoring. Curve *A* represents the cost of improving the enrollment rate estimate through customer surveys; curve *B* represents the cost of promotional efforts to attract customers to the program; and curve C represents the sum of these two costs. The point of minimum total cost (*D*) represents a trade-off between acquiring costly information and incurring costs as a result of innaccurate information.



General monitoring framework

EPRI's demand-side management project has developed a range of tools and information on all aspects of the DSM planning process (RP2548-1). One element of that project resulted in the formulation of a generalized framework for DSM program monitoring, which consists of a sequence of steps. Step 1 is the selection of the monitoring team. The objective of this step is to select a team that can be objective in considering alternative techniques and measuring program performance; has the widest range of data collection and analytical skills available in the company; and has adequate skills to implement the techniques chosen. This step also involves the selection of a team manager who has demonstrated the ability to work effectively with others and who will have the time necessary to plan and implement the monitoring activity and cope with problems that may arise.

In step 2 personnel define monitoring objectives. The objectives for a DSM-program-monitoring activity must be clear, unambiguous, and understood by the team members. Objectives usually include assessing the results of the program, comparing the results with the objectives of the program, and assessing the operational efficiency of the program.

In step 3 the team determines monitoring constraints. Potential constraints can be analytical or operational. Analytical constraints include methodologies mandated by regulatory authority, the quality of performance measurements required by users of the results, and the availability of representative geographic areas for potential research designs that require test and comparison groups. Examples of operational constraints are regulatory reporting requirements, the monitoring budget, the available time, and the reliability of monitoring equipment.

Step 4 involves the resolution of monitoring objectives with constraints and the selection of the monitoring design and techniques. Several factors will influence the analyst's choice of monitoring technique—the role of statistical versus nonstatistical information, the value of the information, the cost of accepting error versus the cost of controlling for error, and other considerations. The selection of appropriate data collection and analytical monitoring techniques will also depend on the specific variables chosen to represent the performance results. These variables can be grouped into the following categories:

- Participation/acceptance. These results refer to customer acceptance of program services or features.
- Operational efficiency. These variables measure the key operational aspects of a program, including, for example, hardware per-

formance or the efficiency of the program delivery system.

▫ Load/energy. These results are direct or indirect kilowatt or kilowatthour measurements that quantify the impacts of the program on the load shape. Data sources include load research results and energy and/or demand readings from billing meters.

▫ Economic. These results are dollar costs and benefits to various parties, including the utility, participants, nonparticipants, or society. The results, or those described below that include these economic results, are typically used as inputs to the utility planning process.

▫ Overall cost-effectiveness. These results include overall aggregate cost-benefit measures that incorporate all antecedent results into a single figure of merit (e.g., a weighted average of different cost-effectiveness perspectives). No new data collection is involved; however, analytical methods may employ elaborate scaling techniques to create the figure of merit.

In step 5 the team develops detailed specifications for applying techniques. This step primarily specifies the details of the data collection method and, secondarily, the analytical techniques for measuring program performance. The specified data and techniques will influence such items as the sample design. If DSM program performance measurements are to be used in future planning or forecasting activities, their specifications may be more stringent than if they are used, for example, as a basis for improving program performance.

Step 6 is the monitoring-technique pretest. Survey questionnaires are often pretested to check such performance factors as question clarity, skip patterns, and questionnaire length. Pretesting may also be used, however, to verify cost assumptions, verify data availability, test a new computer program, and build organizational support for the methods that will generate the performance measurements. The choice of whether or not to pretest the monitoring technique generally depends on available time and budget.

In step 7 the team reevaluates the choice of technique if necessary. The results of this evaluation will indicate whether revisions to the analytical or operating details (i.e., the monitoring design, data specifications, data collection techniques, or analysis techniques) will be required. A decision to change any of these design features at this stage of planning will depend on the trade-offs between the value that design improvements will contribute and the cost of retracing one or more of the preceding steps. If the pretests indicate that different data collection or analytical techniques are worthwhile, new techniques should be chosen at this stage, before developing the monitoring plan.

In step 8 the monitoring plan is developed. This step provides a means for ensuring that the monitoring activity becomes a formal part of the overall program plan and that all utility functional areas with responsibility for parts of the monitoring activity understand those responsibilities. The monitoring plan should be written so that it can be distributed to all parties involved. The monitoring plan should include the objectives as well as both the analytical and operational details of the monitoring activity. All data collection forms and specifications, a description of the responsibilities and reporting hierarchy for the monitoring-team members, schedules, instructions, and quality control program details should appear in the monitoring plan.

Step 9 is the implementation step. The monitoring team should be encouraged to provide feedback on operations that are not working smoothly and to make suggestions for improvements. During implementation of the monitoring plan, it is essential that the monitoring manager initiate routine contacts with the field personnel responsible for data collection rather than waiting for them to make inquiries about problems. In addition, periodic upper-management acknowledgment of the importance of the monitoring activity to the company can go a long way to encourage accurate data collection and team member cooperation.

Step 10 is results analysis. Data entry and general data base cleaning typically necessitate contacting data collection personnel for interpretation or resolution of anomalies. Coordinating the analysis with available computer resources is important because computers are frequently the responsibility of another functional area within the utility. Once results are available, they should be reviewed promptly and interpreted. A good practice for promoting monitoring-team morale is to disseminate early results in some summary form in order to show the outcome of the effort expended.

Step 11 is DSM program reconciliation and reevaluation. The team considers the following factors:

▫ Performance versus objectives

▫ Reasons for discrepancies between performance and objectives

▫ Operational reconciliation (i.e., ways to improve program operations)

▫ Theoretical reconciliation (i.e., analysis of the theory behind the choice of analytical treatment)

▫ Recommended follow-up action

In step 12 the results are distributed. Results should be reported for each of the monitoring objectives. As indicated in step 10, the measurements should be reported in a format that will be useful to the users of the data (which may require that more than one product be prepared). Qualifications of the data, if any, and their implications must be reported so that the users will be able to assess the risks of using the data in their particular applications. For example, all statistical tabulations should include the sample sizes and the numbers of responses represented in the figures (which are usually given as percentages).

Formalizing the process

The importance to the utility industry of implementing a strong monitoring and evaluation activity cannot be overstated. With the increased pressures from regulators and utility management to document the impacts of DSM programs comes a need to improve the industry's ability to measure and analyze those impacts. More utility resources for formalizing monitoring and evaluation processes may be necessary to adequately support management selection of supply-side or demand-side resources.

The results of this EPRI overview of DSM program monitoring and evaluation begin that formalization. Further details on the above framework and other monitoring factors, including utility and nonutility case studies, can be found in EPRI EM-5706. An example of an analysis of the customer acceptance and energy impacts of residential conservation programs appears in EA-3606. EPRI has also issued a number of reports related to load research: EA-3255, EA-3286, EA-3467, EA-3683, EA-3994, EA-4006, and EA-4232.

Geothermal Power Plant Equipment

Correcting Pump Vibration Problems at Heber

by Jonne L. Berning, Generation and Storage Division

ABSTRACT *Rotating equipment failures account for 30–50% of power plant outages, according to NERC GADS statistics. Forced outages have a severe effect on power plants in terms of downtime and lost revenues. Rotating equipment in geothermal binary-cycle plants, as well as fossil fuel plants, usually deteriorates progressively, not suddenly, thereby providing valuable early warning data for analysis and allowing operators to prevent catastrophic failure. The FEATURE computer code, developed by Mechanical Technology, Inc., for the Fossil Plants Availability Program at EPRI, has helped in the attempt to understand the hydrocarbon booster pump problem at the Heber binary-cycle demonstration power plant. The code was used to model rotor dynamics in a study that focused on problems experienced at Heber during the first two years of operation and on modifications aimed at solving those problems.*

San Diego Gas & Electric's Heber binary-cycle geothermal demonstration project is a 45-MW(e) (net) power plant in the Imperial Valley of southern California. The plant converts geothermal heat energy, obtained from a moderate-temperature (360°F) underground brine reservoir, to electric energy. Heat from the geothermal brine is transferred to a hydrocarbon working fluid, which is expanded through a hydrocarbon-vapor turbine to drive a generator.

The closed hydrocarbon fluid circuit has four condensate pumps and four booster pumps. Each set of pumps is designed to handle 25% of the total flow requirement (7.5 million lb/h) for the plant. The pumps were first placed in service in May 1985 during plant startup. Between May 1985 and June 1987 the four booster pumps experienced a total of 32 failures, with a mean time between failures of only 485 hours. Many of the failures involved high vibration and damage to the rotor wear ring seals. The mean time to repair the pumps was 47 days at the manufacturer's shop.

Chronic high vibrations (3–4 mils) were measured during these first two years of operation in all four hydrocarbon booster pumps. All pumps were monitored through the plant's data acquisition system, and periodic testing by SDG&E's Technical Services Division confirmed these values. During this period of operation no pump experienced a catastrophic failure, because an upper vibration limit of 4.3 mils in either the x- or y-axis was imposed to signal when a pump should be taken out of service. All pumps were taken out of service when the upper vibration limit was reached or when a seal failure occurred.

The plant's four hydrocarbon booster pumps are Ingersoll-Rand two-stage, horizontally split centrifugal pumps. Each pump has an operating speed of 3600 rpm and is driven by a 3500-hp motor. The pumps are rated at 8670 gpm at 3580 rpm and boost the fluid from 167 psig to 650 psig while increasing the head to 2109 ft. The working fluid is a 10% (mole-weight) isopentane and 90% (mole-weight) isobutane mixture with a specific gravity of 0.54.

During initial startup and operation the pumps exhibited two frequencies of vibration: one times (1×) the running speed and seven times (7×) the running speed. The 7×

running-speed vibration was reduced to an acceptable level (0.3 mil) by increasing the internal case-to-impeller-tip clearance. The 1× running-speed vibration was still a problem, particularly during rapid load increases, which caused sharp increases in the vibration level; this increased the baseline vibration level after the event.

During the first two years of service, the manufacturer made the following five modifications in an effort to resolve the 1× running-speed vibration. The first four showed no improvement in the vibration problems.

- Modification 1: Changed original steel shaft to a less stiff bronze-nickel alloy; removed cutwater from casing to reduce radial thrust
- Modification 2: Closed the impeller-shroud-to-diffuser radial clearance; welded internal bundle to increase bundle rigidity; streamlined diffuser inlet
- Modification 3: Opened the impeller-vane-to-diffuser-vane clearance; removed material from suction guide vane; changed wear ring material and design from bronze to stainless steel; changed shaft material back to the original steel
- Modification 4: Tapered balance disk configuration; incorporated swirl nozzle in balance disk area
- Modification 5: Changed balance disk to a balance piston

Rotordynamic analysis

After four modifications to solve the problem, high vibration levels persisted. In the fall of 1987, EPRI contracted with Mechanical Technology, Inc., to investigate the cause of the vibration and the pump failures. The failure analysis was to be based on a complete rotordynamic analysis, including the use of an EPRI computer simulation program to model the pumps—FEATURE (Finite-Element Analysis Tool for Utility Rotordynamic Evaluation).

The goals of the EPRI study were to identify the cause of failure and to evaluate the manufacturer's final modification (modification 5), which had been installed on one pump but not tested. The modeling effort evaluated four basic configurations—modifications 1, 2, 3, and 5. Modification 4 was excluded because it essentially changed the pumps back to the original design. The four configurations were analyzed to understand the 32 failures experienced to date and to determine whether modification 5 had resolved the chronic vibration problem.

FEATURE is a flexible, user-oriented tool for analysis of rotor bearing systems. The program performs linear critical speed, damped response, and stability calculations for a wide range of rotor geometries, including multiple, concentric, counterrotating spools and large, multispan, rigidly coupled rotors. EPRI developed the computer code to help utility engineers procure, refurbish, and analyze rotating machinery.

A rotordynamic model was created by using the design data from the manufacturer and actual field measurements from the data acquisition system and SDG&E's Technical Services Division vibration monitoring system. The rotordynamic model did predict the behavior of the pumps. The effort was designed to model the wet and dry critical speed of the pumps in air and in the hydrocarbon mixture. The wet pump rotor with active seals runs very close to the first critical speed, just below it with a steel shaft and just above it with a bronze shaft (modification 1). Furthermore, the rotor mode shape at the first critical speed is that of a flexible rotor on ridge

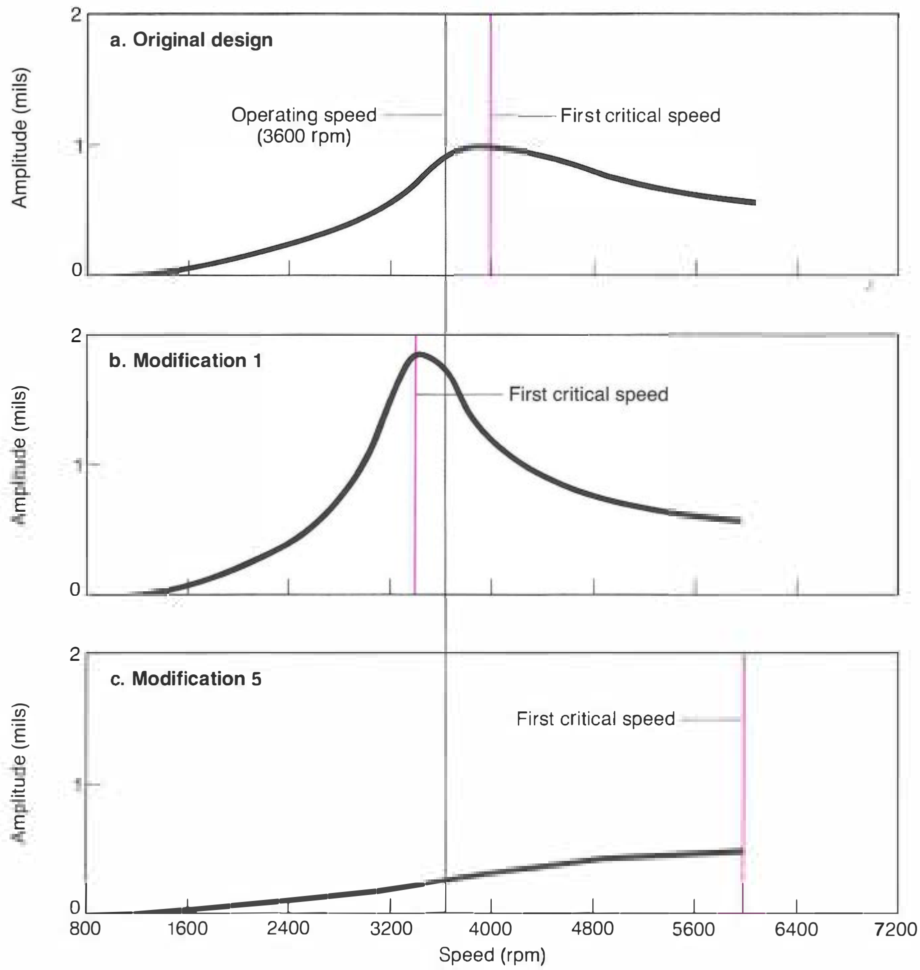


Figure 1 These unbalanced-response test run curves for the rotordynamic models show the original pump rotor design (a) and modifications 1 and 5 (b, c) at the running speed of 3600 rpm. The original design (balance disk, steel shaft) and modification 1 (balance disk, bronze shaft) display a tendency toward high vibration while approaching critical speeds. Modification 5, however, replaces the balance disk with the larger-diameter balance piston, raising the critical speed and significantly reducing the amount of vibration.

bearings. There is virtually no motion at the bearings and therefore no effective damping. The model indicated that the rotor's first critical speed and response to unbalance are controlled almost entirely by the stiffness and damping available from the wear ring seals. If the wear ring seal clearances increase in service as a result of seal wipes (rubbing of the shaft against the seal ring surface), the stiffness and damping of the seals will decrease; the result will be increased vibration of the rotor and increased sensitivity to flow changes with time.

All stability runs made with the rotordynamic model showed that the rotor is stable— i.e., that there is no tendency to subsynchronous vibration. None had been seen in measurements on the operating pumps. The critical speed of the dry rotor, with no support from the wear ring seals, was about 2350 rpm, well below the running speed of 3600 rpm.

Analytical results

The unbalanced-response test runs with the rotordynamic model provided the most important insight into the vibration behavior of the pumps. The response of the original pump rotor design (steel shaft and balance disk) shows that at3600 rpm, the rotor is operating on the steepest part of the response curve, just below the critical speed of 4000 rpm (Figure 1a). The relatively distinct peak indicates a lightly damped system. A rotor operating with these characteristics would be expected to be sensitive, with a tendency toward high vibration unless balance was exceptionally good.

Replacing the steel shaft with one made of bronze (modification 1) produced the response shown in Figure 1b. Here the rotor is operating right on the first critical speed. Again, the slope of the response curve at speeds approaching the critical speed indicates that this rotor, too, would have a tendency toward high vibration. The amplitude of vibration for the applied level of unbalance is the same as that shown for the steel shaft in Figure 1a.

Figure 1c shows the response curve that resulted when the balance disk was replaced with a cylindrical balance piston (modification 5). The larger diameter and close clearance of the piston make it act like a very large bearing, with significant stiffness and cross-coupled damping; this effect is known as the Lomokin effect. Cross-coupling in a bearing produces a component of motion in a direction perpendicular to that of the applied load (or vice versa). As a result, the critical speed is raised above 5000 rpm, and the amplitude and slope of the response curve at 3600 rpm are greatly reduced. The level of vibration is down by a factor of 3. This clearly shows the reason for the reduced vibration measured during the brief (one-hour) test of the rotor equipped with the balance piston. The results of the rotordynamic analysis showed that the last modification by the manufacturer to the booster pumps has clearly produced a superior dynamic system that should operate as specified.

Lessons learned

The rotordynamic analysis demonstrated that the original pumps produced by the manufacturer had a high vibration sensitivity because they operated very close to the first critical speed and were dependent on the modest damping available in the wear ring seals to control rotor response.

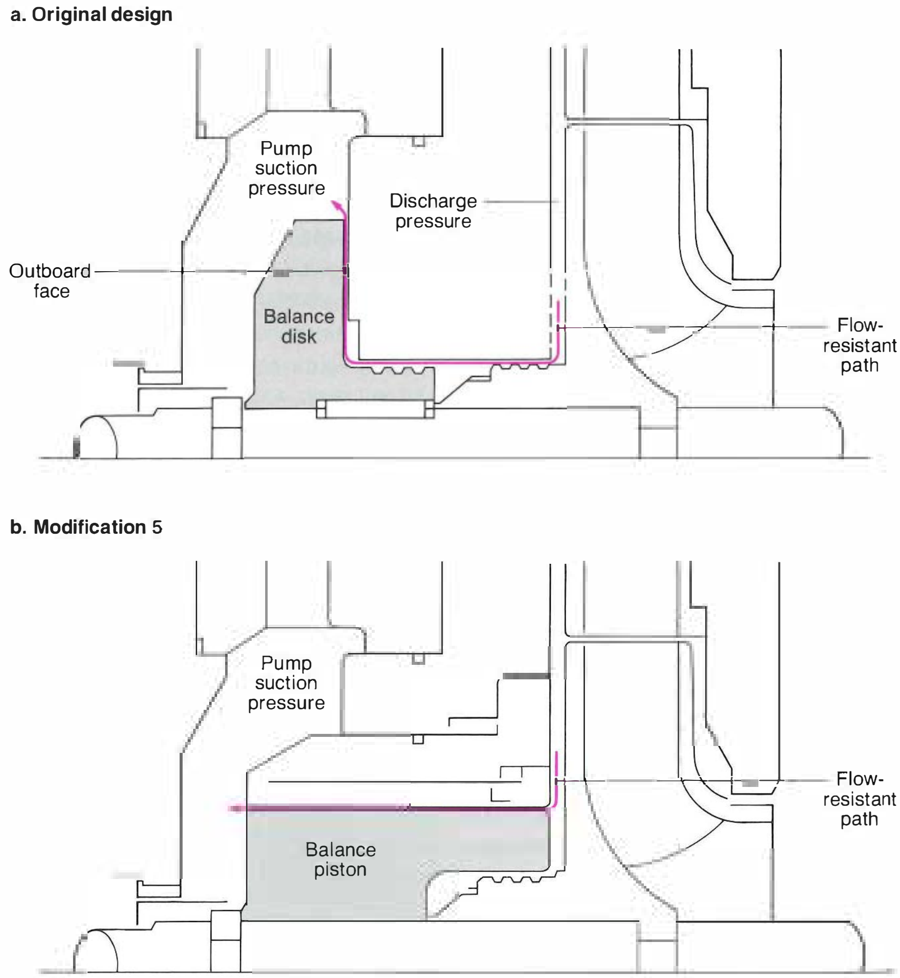


Figure 2 In the original pump rotor design (a), the pressure drop between the discharge pressure and the pump suction pressure at the outboard face of the balance disk causes proportional radial stiffness, a decrease in radial support, and increased vibration. In modification 5 (b), however, because the piston clearance and pressure drop do not change during axial movement of the balance piston, there is no increase in vibration and no change in radial stiffness.

An additional feature of the observed performance remained to be explained, however The pumps equipped with balance disks (the original design) were always sensitive to sudden load increases. Under these conditions they experienced rapid increases in vibration—often to the alarm, or trip, levels for the pumps. The operator could usually reduce the high vibration by reducing the load on the pump. The rotor equipped with the balance piston did not experience the increased vibration during the one-hour test, in which a large, sudden, unexpected load increase occurred.

During the calculation of wear ring stiffness, an observation was made that might explain the cause of the vibration increases during flow transients. The area between the balance disk and the second-stage impeller forms three flow resistances in series (Figure 2a). The pressure drop that takes place between the second-stage discharge pressure and the pump suction pressure at the outboard face of the balance disk has a radial stiffness that is proportional to the pressure drop. The portion of the total pressure drop attributed to the balance disk is a function of the clearance across the disk face. When a large load increase occurs in the pump, the increased load on the thrust bearing causes the rotor to move toward the suction, decreasing the clearance in the thrust disk. The pressure drop across the disk increases, which leaves less of the total drop to be taken across the hub seals. Their stiffness declines as a result, and the rotor has less radial support.

This is the mechanism through which pump load and rotor support are coupled. As the stiffness of the hub seals is reduced, the critical speed decreases to coincide with the running speed, whereby vibration increases. The cause of the increase in vibration with load increase for the balance disk design is now clear This same reasoning also explains why no increase in vibration occurred with the rotor equipped with the balance piston (Figure 2b): there is no change in seal stiffness with axial movement of the balance piston because the piston clearance and pressure drop remain unchanged.

The importance of seal stiffness in controlling rotor critical speed leads to an explanation for the gradual increase in vibration with operating time with the booster pumps. Each load excursion that led to a vibration increase caused minor seal wipes. Each wipe resulted in an increase in seal clearance and a corresponding drop in seal stiffness. The loss of rotor support lowers the critical speed slightly, which means that the rotor is operating closer to the critical speed and higher on the response curve. This leads to progressive deterioration in the rotor's performance until it has to be removed from service for high vibration. It is now understood why virtually all rotors removed from service for high vibration had wiped wear ring seals.

Rotordynamic modeling with FEATURE has proved to be an effective means of understanding the vibration problem experienced with the Heber binary-cycle hydrocarbon pumps. If this method of analysis had been used earlier most of the failures could have been prevented and the vibration problem could have been resolved early in the project.

Transportation costs alone to ship the four pumps back to the manufacturer for modifications would have paid for this type of rotordynamic analysis four times over during the two-year period that the vibration problem persisted. Both pump manufacturers and utilities can benefit from this analysis tool—not only in resolving vibration problems in rotating equipment, but also in designing plants where large-capacity pumps are to be custom designed and installed for first-time applications.

Electric Transportation

Progress in Electric Van Development

by Gary Purcell, Customer Systems Division

As part of its electric vehicle (EV) research, EPRI has joined with Southern California Edison and the U.S. Department of Energy to sponsor the development of the Chrysler TEVan (RP2664-4). This electric minivan (Figure 1) will feature a 1200-pound payload capacity and room for six passengers or 120 cubic feet of cargo. Its projected range of 120 miles between battery charges is double that of the EPRI-developed electric G-Van, a larger van with greater cargo capacity (RP2664-8).

The TEVan will be the first production EV designed specifically for use as a light cargo or passenger vehicle. The initial market for this van will be commercial fleets, because fleet vehicles are generally parked in a central area overnight, which facilitates battery recharge. Fleet owners can also perform EV maintenance in-house, eliminating the need for separate maintenance facilities.

According to a recent survey, the *National Market Study of Electric Van Potential,* the TEVan's 120-mile range meets the requirements of over 80% of fleet vehicles. Possible applications include employee and visitor transport, employee vanpools, security patrols, deliveries, and customer service calls.

The TEVan is also suitable for the personal-vehicle market. Because of its performance and design, the TEVan could replace vans, passenger cars, and station wagons. However, its entry into the personal market depends on the establishment of a nationwide EV service system.

Performance and design

The TEVan's projected sustainable top speed of 65 miles per hour and 7-second acceleration from 0 to 30 miles per hour will ensure its

ABSTRACT *Modern electric vehicles, now approaching commercialization, offer a promising new market for electricity while providing important benefits to society—better air quality and less demand for imported oil. Together, the utility industry, government agencies, and major automotive manufacturers have been working to develop EVs that will appeal to American consumers. One promising candidate, the Chrysler TEVan, could be operating in utility fleets as early as 1991.*

compatibility with highway traffic. The new van will also use fuel efficiently; its target energy consumption of 0.43 kWh per mile is equivalent to 44 miles per gallon (in urban traffic) for a conventional vehicle (at 5¢ per kWh and 95¢ per gallon of gasoline). The van's clean, quiet operation and relatively low maintenance requirements will also make it a pleasure to own.

The TEVan is based on the popular Chrysler minivan body used in the Plymouth Voyager and Dodge Caravan. It will be powered by a 39-kWh, 180-V nickel-iron battery developed by Eagle-Picher Industries. This battery has a longer life than any lead-acid battery and has one-third more energy storage capacity per unit weight than the 3ET205 lead-acid battery used in the G-Van. The battery pack, which contains thirty 6-V modules, rests in a tray beneath the vehicle floor and does not intrude into the cabin area.

A special microprocessor-based battery management system will control battery temperature, hydrogen concentration, watering, and charging. The microprocessor will also rapidly diagnose any failures of individual battery cells. This unique management system will minimize the need for routine maintenance; the battery pack will require visual inspections only twice a year and an annual capacity check to identify potentially weak cells.

The controller, charger, and dc-dc converter will be integrated into a single compact unit placed under the hood for easy access. Because the charger is built in, the TEVan can be plugged into any 220-V outlet. The controller configuration will also reduce component space requirements, propulsion system weight, and total vehicle system cost.

Many other components have been specially designed and adapted for the TEVan, so that the driving experience will closely resemble that provided by conventional minivans. An electronically shifted two-speed transmission will contribute to the van's range, gradability, and performance. An electronic instrument cluster with a full array of standard gauges will help the driver monitor key indicators. Other special components include a dc motor and electrically driven power brakes and steering. Regenerative braking will supplement the mechanical braking system and extend vehicle range as much as 15%.

Like other EVs, the TEVan is inherently reliable: EV propulsion systems have fewer moving parts—and therefore require less maintenance—than propulsion systems used in conventional vehicles.

Figure 1 The Chrysler TEVan. Initial production of this electric minivan, the first designed for light cargo or passenger vehicle use, is planned for 1991.

Status and plans

At present, Chrysler is constructing four proof-of-concept TEVans, which should be completed by early 1989. Chrysler will then perform a vehicle cost analysis to determine TEVan life-cycle costs and help establish an appropriate purchase price.

Complete performance testing of one of the proof-of-concept TEVans will take place at the Electric Vehicle Test Facility in Chattanooga, Tennessee. These tests will include standard assessments of vehicle energy consumption, range, acceleration, top speed, braking performance, and climbing ability. After completion of these tests, Chrysler will build several prototype vans for utility-fleet field testing in late 1989. Initial production is planned for 1991. Meanwhile, EPRI will take part in developing production processes for, and initial quantities of, vehicle batteries at a pilot facility.

Key benefits

EVs, including the TEVan, offer a number of important social benefits. Because electricity is a clean fuel, EVs do not emit harmful pollutants. Widespread use of EVs can also help ease U.S. dependence on foreign oil and reduce the trade deficit, because most electricity is produced from domestic resources. And since most EVs would be recharged at night, their use would improve utility load factors and could help stabilize electricity rates for all customers.

In addition to these social benefits, EVs also offer substantial advantages to the utility industry. Widespread use of EVs would mean a considerable new market for electricity: each TEVan will use about as much electricity as one new residential customer. Off-peak vehicle charging would help many utilities better meet load management objectives. And by helping to improve air quality and reduce the trade deficit, EVs represent an outstanding public relations opportunity for individual utilities.

One utility has already made a strong commitment to supporting the TEVan. Southern California Edison, concerned about the declining air quality in the Los Angeles basin, has cosponsored TEVan development and will be the first utility to use and exhibit the van. Beginning in 1989, SCE will be demonstrating two proof-of-concept vans to potential government and private buyers. SCE also plans to solicit the support of legislators and regulatory agencies by showing how the new van and other EVs can help solve pervasive air quality problems.

As new EVs like the TEVan achieve visibility in the fleets of electric utilities and other businesses, momentum should build for the introduction of advanced EV technology. Ongoing EPRI research is developing and evaluating advanced batteries (RP2415-7), ac drivetrains (RP2861-1), and hybrid-fueled extended-range EVs (RP2664-5).

Fossil Fuel Plant Availability

Fly Ash Erosion of Boiler Tubes

by Barry Dooley, Generation and Storage Division

ABSTRACT *Boiler tube failure due to fly ash erosion is one of the leading causes of availability loss in fossil fuel boilers. The damage, which can be very localized, has led to expensive and sometimes lengthy forced outages. Unfortunately, most of the available remedies for fly ash erosion have proved to be temporary. EPRI is sponsoring a broad effort to provide U.S. utilities with permanent solutions to this problem. Current work involves the demonstration of a cold-air-velocity technique, which foreign utilities have used successfully, and laboratory studies with run-of-mine and cleaned coals to document the velocity dependence of the erosion process.*

Boiler tube failure (BTF) is the leading cause of availability loss in U.S. power plants. The equivalent availability loss attributable to BTF is over 6%. A large percentage of the tube failures are repeats caused by a recurring problem. Failures have occurred in all boiler areas: economizers, waterwalls, superheaters, and reheaters. More than 80% of BTFs force a shutdown, and a typical outage lasting three days can cost a utility $750,000 for replacement power.

As part of a multifaceted approach to the problem, EPRI has developed a manual for power plant personnel to use in investigating BTF causes (EPRI CS-3945). Determining the correct failure mechanism and root cause in each case is of paramount importance. Proper corrective action can then be taken to alleviate the root cause, adopt monitoring procedures, and thus eliminate repeat failures. The manual is being used in most U.S. power plants. EPRI is working with 20 host utilities to demonstrate a BTF reduction approach based on the manual and has developed additional training materials for all levels of utility personnel (RP1890-7).

Of the 22 failure mechanisms described in the manual, only two require further R&D to determine the root cause: corrosion fatigue failures that initiate on the waterside of waterwall and economizer tubing, and circumferential waterwall cracking that begins on the fireside surfaces of supercritical units. Projects are under way in both of these areas to provide predictive techniques and permanent solutions (RP1890-5, -8).

Two other BTF mechanisms, fly ash erosion and fireside corrosion, require further work to demonstrate the effectiveness of potentially permanent solutions. A recent EPRI project surveyed utilities and boiler manufacturers to assess the importance of these mechanisms in overall availability (CS-5071). State-of-the-art techniques being applied to the problems were also evaluated. Fly ash erosion of superheater, reheater, and economizer tubing is a more serious problem than fireside corrosion, although fireside corrosion of waterwalls appears to be increasing in importance. Currently the problems are being effectively managed by extensive maintenance and by such temporary measures as pad welding and the fitting of tube shields and baffles. Although proven permanent solutions are available for most of the problems encountered, they are not being applied because installation costs are perceived as higher than the costs of continued maintenance. Nevertheless, fly ash erosion and fireside corrosion still cause several forced outages annually, and most are repeat failures.

Foreign utilities have implemented some permanent solutions for fly ash erosion and fireside corrosion, including the use of more resistant alloys or cladding and the use of a cold-air-velocity (CAV) monitoring technique that enables better location of preventive diffusing screens, baffles, and shields. The efficacy and cost-effectiveness of these techniques are being demonstrated at two U.S. utilities (RP2711-2).

Cold-air-velocity technique

Six courses of action are available to utilities for reducing fly ash erosion in any location in a boiler:

- Reduce the bulk flue gas velocity
- Reduce the local gas velocity by baffling
- Even out the gas flow across the boiler section to remove localized turbulent regions
- Reduce the fly ash loading
- Even out the concentration of fly ash across the boiler section
- Decrease the erosivity of fly ash

The installation of baffles has been the most commonly used method. However, solid plate baffles intended to prevent gas flow between the tube banks and the walls have often acted to deflect and concentrate a stream of fly ash onto adjacent tubes, causing highly localized wastage. This inaccurate placing of baffles has been one of the most common causes of repeated erosion failures.

The CAV technique is used to even out gas flow and fly ash concentration across the boiler section. It involves the mapping of cold-air velocities at a large number of locations in the boiler to develop velocity profiles for the complete flow cross section. These profiles are then used to identify areas of high gas velocities where screen baffles should be installed. The information can also be used to quantify the resistance to flow required in these areas to produce a uniform profile over that particular boiler cross section. After screen baffles have been installed, the velocity profiles are remeasured at the same locations to verify the baffles' effectiveness and to look for any new high-velocity flows.

The velocity measurements are made during scheduled downtime when the boiler is cold. The measured cold-flow velocities are converted to hot-gas velocities by using temperature-related correction factors, which are applied to account for the differences between cold and hot gas and for the effects of heat transfer in the tube banks. The screens are made of stainless steel, typically Type 304 or 309, as expanded metal; the open area of the screens varies from about 40% to 70%.

The CAV technique is being demonstrated in Potomac Electric Power's Morgantown unit 2 and Arizona Public Service's Four Corners unit 3, both of which have experienced serious fly ash erosion problems. Figure 1

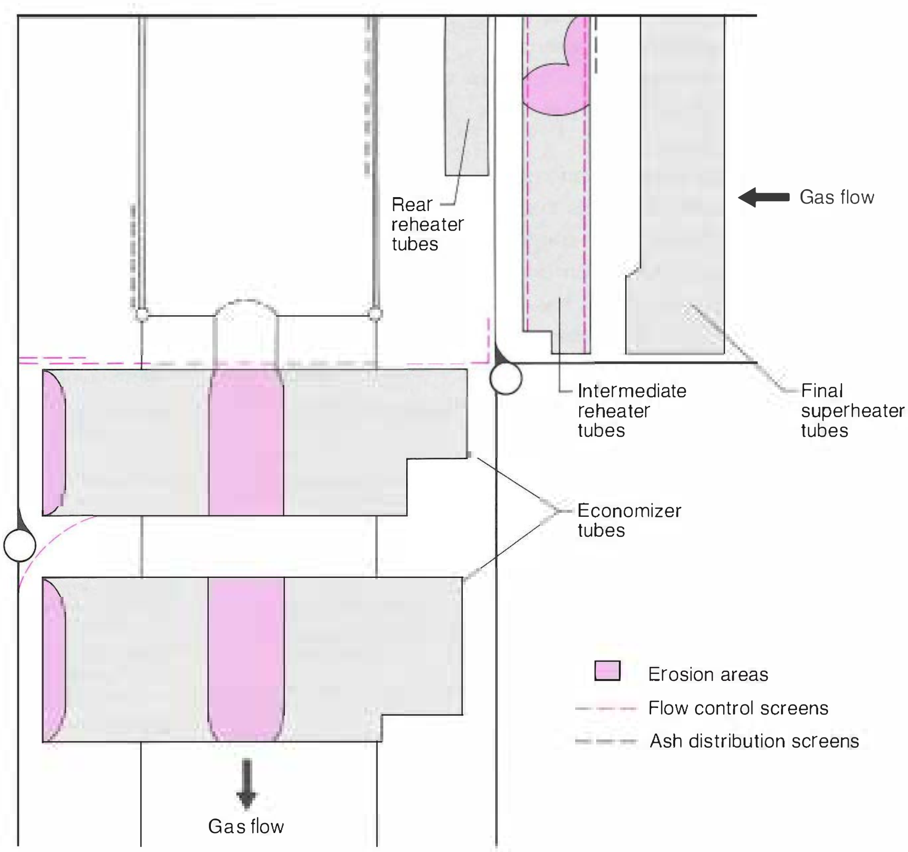


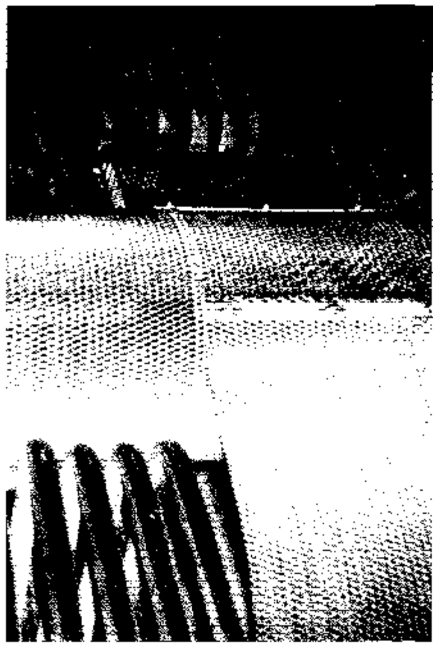
Figure 1 In a demonstration at a utility boiler, screens have been installed to reduce tube erosion by controlling flue gas flow and ash distribution. The use of such screens, in conjunction with a cold-air-velocity technique for determining where to position them, is a promising remedy for this common utility problem.

shows where screens have been positioned to reduce tube erosion in the boiler convection and economizer sections of one of these units. Screens installed along the gas flow lanes through the tube banks act to reduce channeling. The domed screen (45–50% open) over the untubed space in the economizer section has been found to be much more effective than a flat screen at the same location (Figure 2). A warped screen (also 45–50% open) helps control flow in the area between the economizer banks. Another important feature is the use of ash distribution screens (65–70% open) to intercept and redistribute ash particles being forced centrifugally toward the unit's back wall.

The expanded-metal screens have proved effective in controlling flue gas velocities in the boiler. According to CAV measurements, most of the high initial velocities have been reduced, and in general the flue gas velocity profile is much more even. In a few locations gas velocities increased after screen installation; since ash particle loadings are lower in those areas, however, the erosion potential is not expected to increase.

Over the next two years the unit will be inspected during overhaul periods to check the continued effectiveness of the screens; a selection of tubes will also be monitored for thickness to ensure that erosion has been eliminated. On the basis of experience with the CAV technique and expanded-metal screens in Canada, Australia, and Germany, this technique is expected to become the cost-effective solution for controlling fly ash erosion in the United States.

Figure 2 This domed screen in the gap between economizer tube bundles is successfully reducing gas velocities in the region and thereby helping to control tube erosion.



The technique can also be applied to new coal-fired units during the commissioning period to ensure that fly ash erosion is not a problem during the life of the boiler.

Causes of fly ash erosion

From numerous studies of erosion, the most important variables appear to be fly ash particle velocity and size, angle of impingement, and coal and fly ash characteristics. The effect of impact velocity is particularly important, since the rate of erosion loss has usually been found to be proportional to the velocity raised to a power of between 2 and 4. The abrasive characteristics of fly ash are determined by the hardness, shape, and size of fly ash particles. Quartz particles are harder than glassy particles of fused ash and are usually angular in shape rather than spherical. Thus methods of correlating the abrasiveness of fly ash are based on the content of (free) quartz.

In a project to evaluate the overall combustion characteristics of coals, both run-of-mine and cleaned coals have been burned in the Combustion Engineering pilot-scale combustion facility. Fly ashes from seven of these coals have been tested in an ash erosion test facility (RP2425). This testing consists of entraining the fly ash in a hot simulated flue gas stream at 800°F (427°C) and bombarding flat coupon samples at velocities of 110 to 350 feet per second. Preliminary results have indicated that the velocity dependence of the erosion rate varies between 2.7 and 5.5. Further analysis of particle size and quartz content is planned that will improve the relationships with fly ash characteristics and ultimately boiler tube erosion predictions.

New Contracts

Project	Funding/ Duration	Contractor/EPRI Project Manager
Customer Systems		
Electric G-Van: Development for Production (RP2664-8)	$404,000 5 months	Conceptor Industries, Inc./ *G. Purcell*
Conduction Mechanisms in Particulate Layers at High Pressure and Temperature (RP8000-37)	$49,600 10 months	Calvert, Inc./*O. Tassicker*
Theoretical Studies of Oxygen Defects in Oxide Superconductors (RP8009-7)	$128,500 23 months	University of Minnesota/ *T. Schneider*
Electrical Systems		
Robust Adaptive Transient Damping in Power Systems (RP2665-1)	$200,000 36 months	Montana State University/ *C. Frank*
Generation and Storage		
Retrofit Combustion NO_x Control Guidelines for Coal-Fired Utility Boilers (RP2154-15)	$116,700 12 months	Fossil Energy Research Corp./*A. Kokkinos*
Field Evaluation of N_2O Analyzer (RP2154-16)	$25,000 2 months	University of California, Irvine/*A. Kokkinos*
Wellhead Power System Development (RP2195-6)	$1,300,000 11 months	Pacific Gas and Electric Co./*J. Berning*
Fossil Fuel Boiler Maintenance Technology (RP2504-2)	$1,187,700 31 months	Babcock & Wilcox Co./ *D. Broske*
Operation and Maintenance Guidelines for Coal Pulverizers (RP2504-6)	$253,000 16 months	Combustion Services, Inc./ *D. Broske*
Composite Ceramic Materials Characterization (RP2608-2)	$77,200 7 months	General Electric Co./ *W. Bakker*
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Emissions From Wall-Fired Low-NO_x Burner Retrofits (RP2916-8)	$305,600 6 months	Fossil Energy Research Corp./*D. Eskinazi*
Superconducting Magnetic Energy Storage: Engineering Test Model R&D (RP2988-2)	$100,000 2 months	Bechtel Group, Inc./ *R. Schainker*
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Preliminary Design of Catalyst-Testing Facility for the EPRI High-Sulfur Test Center (RP3004-5)	$29,200 5 months	Fossil Energy Research Corp./*E. Cichanowicz*
Natural-Gas-Fueled Molten Carbonate Fuel Cell Power Plant Development (RP3059-1)	$1,093,800 18 months	International Fuel Cells Corp./*R. Goldstein*
Advanced Concepts for Molten Carbonate Fuel Cells (RP3059-2)	$556,100 7 months	Institute of Gas Technology/ *G. Cook*

Project	Funding/ Duration	Contractor/EPRI Project Manager
Nuclear Power		
Stress Corrosion Cracking Behavior of High-Chrome Welding Alloys (RP1566-3)	$160,700 20 months	Babcock & Wilcox Co./ *L. Nelson*
Empirical Evaluation of the Effects of Power Plant Lighting on Human Performance (RP1637-9)	$99,800 12 months	Advanced Resource Development Corp./ *J. Parris*
Use of a Corrosion Fatigue Model to Scale Pressure Vessel Data (RP2006-21)	$49,800 24 months	CISE/*J. Gilman*
Nondestructive Evaluation of Component Interiors (RP2057-10)	$135,100 12 months	Southwest Research Institute/*M. Avioli*
Stress Corrosion Cracking of High-Strength Alloys (RP2181-6)	$40,000 1 month	Babcock & Wilcox Co./ *L. Nelson*
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Radioactive Waste Volume Reduction and Solidification Systems: Byron and Fermi-2
NP-5957 Topical Report (RP1557-1); $32.50
Contractor: Sargent & Lundy
EPRI Project Manager: P. Robinson

Disposal of Uncontaminated Dry Active Waste
NP-5958 Final Report (RP1557-9); $25
Contractor: National Nuclear Corp.
EPRI Project Manager: P. Robinson

Crack-Opening Area Calculations for Circumferential Through-Wall Pipe Cracks
NP-5959-SR Special Report; $32.50
EPRI Project Manager: D. Norris

PWR Primary Water Chemistry Guidelines: Revision 1
NP-5960-SR Special Report; $32.50
EPRI Project Manager: C. Wood

Adaptation of the PARIS Technology for Measuring Wall Thinning in Ferritic Steel Components
NP-5961 Final Report (RP1570-22); $32.50
Contractor: Sigma Research, Inc.
EPRI Project Manager: S. Liu

Evaluation of NASA's Launch Processing System for Nuclear Power Applications
NP-5962 Final Report (RP2902-3); $32.50
Contractor: Systems Control, Inc.
EPRI Project Manager: J. Naser

Lamb Wave Inspection for Large Cracks in Centrifugally Cast Stainless Steel
NP-5963 Interim Report (RP2405-23); $32.50
Contractor: Georgetown University
EPRI Project Manager: M. Avioli

Problem Assessment of Discrete Radioactive Particles
NP-5969 Final Report (RP2412-6); $32.50
Contractor: Vance & Associates
EPRI Project Manager: P. Robinson

Reconnaissance Investigation of the March 2, 1987, New Zealand Earthquake
NP-5970 Final Report (RP2848-6); $32.50
Contractors: EQE Inc.; Cygna Energy Services
EPRI Project Manager: R. Kassawara

1987 EPRI Workshop on Secondary-Side Intergranular Corrosion Mechanisms: Proceedings, Vols. 1 and 2
NP-5971 Proceedings (RPS407-7); Vol. 1, $25; Vol. 2, $10,000
Contractor: Dominion Engineering, Inc.
EPRI Project Manager: P. Paine

Radwaste Radiolytic Gas Generation Literature Review
NP-5977 Final Report (RP2724-1); $25
Contractor: Sargent & Lundy
EPRI Project Manager: P. Robinson

Verification and Validation of Expert Systems for Nuclear Power Plant Applications
NP-5978 Final Report (RP2582-6); $32.50
Contractor: Science Applications International Corp.
EPRI Project Manager: J. Naser

Wave-Propagation Studies for Improved Ultrasonic Testing of Centrifugally Cast Stainless Steel
NP-5979 Topical Report (RPS2405-18); $32.50
Contractor: Drexel University
EPRI Project Manager: M. Avioli

Assessing the Impact of NRC Regulation 10CFR61 on the Nuclear Industry
NP-5983 Final Report (RP2412-6); $32.50
Contractor: Vance & Associates
EPRI Project Manager: P. Robinson

Boric Acid Corrosion of Carbon and Low-Alloy Steel Pressure-Boundary Components in PWRs
NP-5985 Final Report (RP2006-18); $25
Contractor: Combustion Engineering, Inc.
EPRI Project Manager: R. Pathania

Proceedings: 1987 EPRI Workshop on Mechanisms of Primary Water Intergranular Stress Corrosion Cracking
NP-5987M Proceedings (RPS407-7); $25
Contractor: Dominion Engineering, Inc.
EPRI Project Manager: A. McIlree

Effects of Control-Room Lighting on Operator Performance: A Pilot Empirical Study
NP-5989 Final Report (RP1637-7); $25
Contractor: Advanced Resource Development Corp.
EPRI Project Manager: H. Parris

Improved PWR Waste Liquid Processing Using Zeolite and Organic Ion-Exchange Materials
NP-5991 Final Report (RP2414-4); $500
Contractor: Babcock & Wilcox Co.
EPRI Project Manager: P. Robinson

CALENDAR

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

MARCH

2–3
Capital Budgeting Seminar: Economic Evaluation of Utility Projects and Contracts
San Diego, California
Contact: Stephen Chapel, (415) 855-2608

6–9
Symposium: Stationary Combustion NO_x Control
San Francisco, California
Contact: David Eskinazi, (415) 855-2918

7–9
Symposium: Energy Utilization
San Francisco, California
Contact: David Rigney, (415) 855-2419

7–9
Solid-Particle Erosion in Steam Turbines
New Orleans, Louisiana
Contact: Tom McCloskey, (415) 855-2655

14–16
Power System Planning and Design: Research Needs and Priorities
Houston, Texas
Contact: Mark Lauby, (415) 855-2304

21–23
Substation Automation
Atlanta, Georgia
Contact: Larry Mankoff, (415) 855-2713

APRIL

11–12
Utility Strategic Issues Forum
Kansas City, Missouri
Contact: Sherman Feher, (415) 855-2838

18–20
Workshop: Coal Weighing and Sampling
St. Louis, Missouri
Contact: Clark Harrison, (412) 479-3503

19–21
Management of Manufactured-Gas Plant Sites
Pittsburgh, Pennsylvania
Contact: Ishwar Murarka, (415) 855-2150

25–28
Seminar: Transmission Line Foundations
Palo Alto, California
Contact: Vito Longo, (415) 855-2287

Authors and Articles


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Yeager


Smith


Wolk


Schainker


Preston


Mehta


Amarnath


Pollak

Quickening the Pace in Clean Coal Technology (page 4) was written by John Douglas, science writer, with technical guidance from research managers in EPRI's Generation and Storage Division.

Ian Torrens has directed the Environmental Control Systems Department since he joined the Institute in July 1987. He was formerly with the Organization for Economic Cooperation and Development for 14 years, including 7 years in the Environment Directorate, in Paris, as head of the pollution control division. He was at one time a researcher with the French atomic energy commission.

Kurt Yeager, an EPRI vice president and division director since 1979, heads the newly established Generation and Storage Division. A program manager when he came to EPRI in 1974, he directed the Coal Combustion Systems Division for nine years. Yeager was previously with the EPA and Mitre Corp.

Ron Wolk, director of the Advanced Fossil Power Systems Department since 1980, managed EPRI's research on clean liquid and solid fuels before that. He came to the Institute in 1974 after 16 years with Hydrocarbon Research, Inc.

George Preston, director of the Fossil Power Plants Department, has been with EPRI since 1978. He was a program manager until 1980, assistant to the division director for a year, and director of the Environmental Control Systems Department until assuming his present position in 1984. He was previously with Occidental Research Corp. for seven years. ■

Freeze Concentration: An Energy-Efficient Separation Process (page 16) was written by John Douglas, science writer, in cooperation with **Ammi Amarnath** of EPRI's Customer Systems Division.

Amarnath came to EPRI in January 1988 to manage research in electrotechnologies for process industries. He had previously worked for seven years as a process engineer and supervisor for two process equipment manufacturers, K-Sons Ltd. and Metito International. ■

Is Cost the Only Measure of Electricity Value? (page 22) was written by Ralph Whitaker, *Journal* feature editor, and is based on a paper by two research managers in EPRI's Customer Systems Division and the investigator on one of their projects.

Philip Hanser, a senior project manager in the Demand-Side Planning Program since April 1986, was formerly with the Sacramento Municipal Utility District for five years as a senior economist in system planning. Between 1981 and 1986 he was an assistant professor in economics and mathematics at the University of the Pacific.

William Smith, manager of planning and information in the Demand-Side Planning Program, has been with EPRI since 1985. He was formerly at Pacific Gas and Electric Co. for eight years, ultimately as supervisor of load management projects. ■

Pioneering CAES for Energy Storage (page 30) was written by David Boutacoff, *Journal* feature writer, aided by three research managers of the Energy Storage Program in EPRI's Generation and Storage Division.

Robert Schainker, a staff member since 1978, joined the program in 1980 and was named to manage it in 1985. He had earlier managed combustion turbine development projects for two years. Schainker was formerly with Systems Control, Inc., for nine years.

Ben Mehta is a project manager with a special interest in hydrogen technology. He came to the Energy Storage Program in 1984 after seven years in EPRI's fuel cell research. Before 1977, Mehta was a senior project engineer with the Lummus Co. in Canada for five years and a process development engineer for Sherritt Gordon Mines for seven years.

Robert Pollak has managed EPRI projects in compressed-air energy storage research for nearly three years. He joined EPRI in 1987 after a year on loan from Bechtel National Corp., where he had worked since 1968 and was a mechanical engineering group supervisor. ■

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