Pumping Heat Energy

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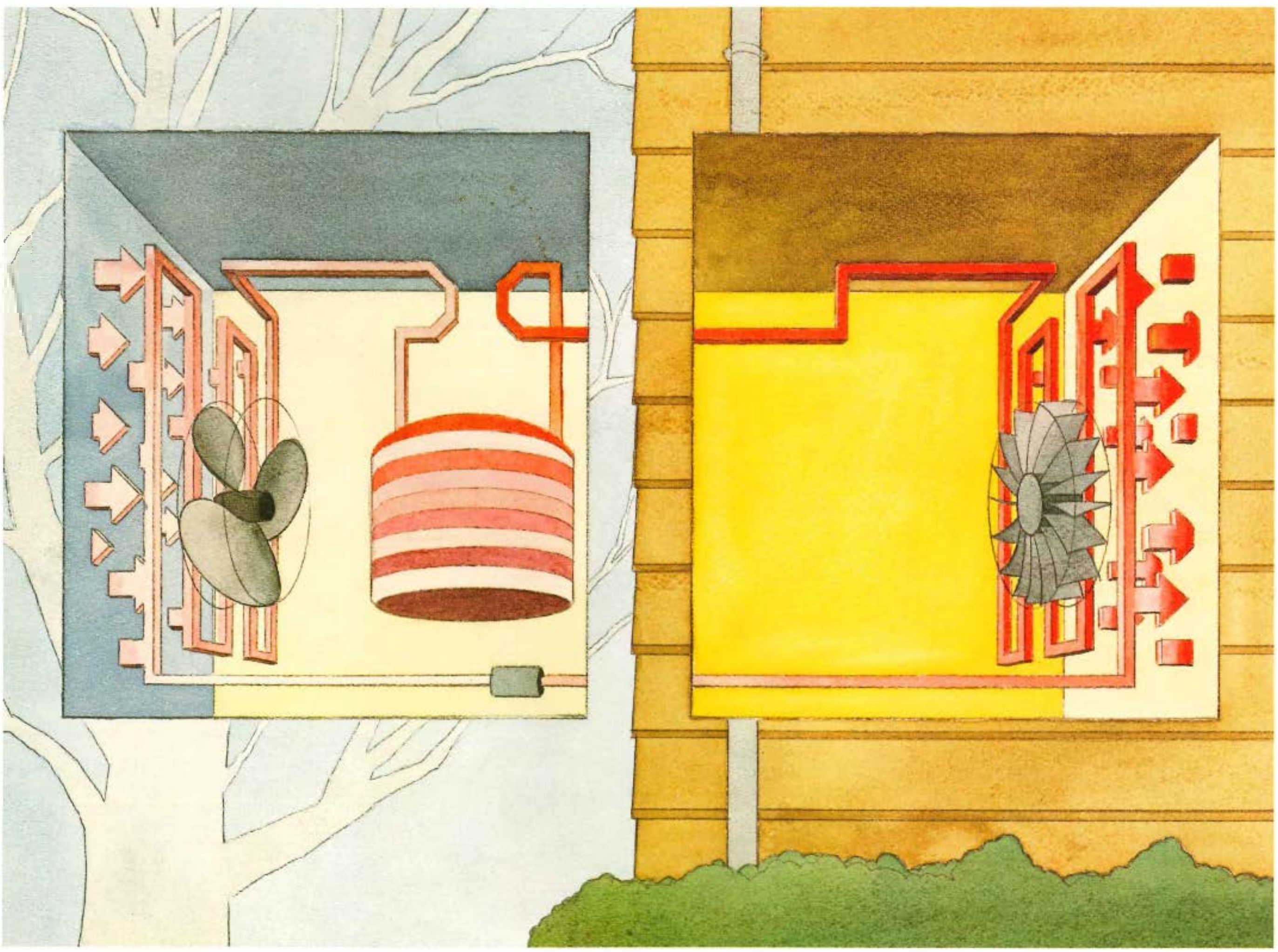

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Cover: The electric heat pump is the most efficient means of using electricity for space conditioning. In winter, heat from the environment is collected and moved inside; in summer the process is reversed.

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Heat Pumps: The Efficient Option

Energy conservation clearly calls for widespread application of the electric heat pump, and this month's cover story reports on the evolution and application of this technology. The electric heat pump meets the triad of electric utility conservation objectives—to improve energy end-use efficiency (it delivers as much as two or more units of usable space-conditioning energy for each unit of electric energy); to manage loads (it fills valleys for summer-peaking utilities and manages winter peaks with less severity than resistance heating); and to substitute electricity generated from indigenous resources for imported oil.

The electric heat pump, whether it is heating or cooling, exemplifies the Carnot cycle in reverse. Its inputs are low-temperature heat from the environment (ambient air, ground, groundwater, solar, or waste resources) and from electrically driven mechanical devices. Measured by a coefficient of performance, the heat pump's efficiency for heating has a theoretical limit of 18 when using a 40°F (4°C) environmental source to warm a building to 70°F (21°C). Although a variety of real-world effects, ranging from air movement losses to motor losses, prevent the achievement of this theoretical limit, it does indicate substantial room for improvement through research.

EPRI's Energy Management and Utilization Division is now organizing a major effort to advance the state of the art of electric heat pump technology by extending previous exploratory analytic work and field-testing projects. The goal is to develop designs and to establish proof of concepts for major advances in efficiency and improvements in the peak demand characteristics of heat pump systems. Utility industry support of research and development is needed if equipment with reduced peak demand (in addition to reduced energy consumption) is to become commercially available. This major project will be cooperatively supported by EPRI and HVAC manufacturers. DOE support will also be solicited, particularly in the applied research and exploratory developments.

Today the electric heat pump is the only commercially proven heat pump technology that has met the tests of producibility, cost-effectiveness, reliability, and customer acceptance. Further, it is an approach to reducing oil imports. In the residential and commercial sectors, government statistics report a present oil consumption of more than three million barrels a day, primarily for space and water heating. If only 20–30% of oil-space-heating customers use the heat pump to supplement or replace oil, the savings would be over half a million barrels a day.

Orin Zimmerman, Director
Energy Utilization and Conservation Technology
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Authors and Articles

Moving stifling summer heat from building interiors to the atmosphere outside has been the job of air conditioners for 30 years or more; in this application the electric heat pump is familiar and reliable.

Directing Heat Flow (page 6) surveys R&D to make the heat pump equally familiar when it is turned around and used for space heating. Special concerns are the low-temperature economy and reliability necessary if the heat pump market is to move gradually northward. Mary Wayne wrote the article, with guidance from Arvo Lannus, manager of EPRI's heat pump technology.

Before joining the Energy Management and Utilization Division in May 1980, Lannus was with Gordian Associates Inc. for six years. As its director of advanced technology, he managed research and consulting activities in energy-efficient equipment and practices, among them heat pumps, combustion systems, energy storage, load management, and solid waste. Earlier, he was an assistant professor of chemical engineering at Cooper Union College in New York for four years. Lannus graduated from Drexel University in 1960 with a BS in chemistry and was an industrial research chemist for six years before returning to Drexel for a PhD in chemical engineering.

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Under some circumstances, the earth itself serves as an electrical conductor. A dc transmission system may operate at more than 50% load with one of its two conductors out of service, using the earth as a return path. But that underground current hitchhikes along buried pipelines whenever it can, often causing electrolytic corrosion and leaks. **MRTB—A New DC Breaker** (page 16) describes R&D whereby utilities can quickly and reliably switch dc power back overhead. Jenny Hopkinson, *Journal* feature writer, adapted a paper by Narain Hingorani, originator of the device and an EPRI program manager in the Electrical Systems Division, and Joseph Porter of EPRI's Washington Office.

Hingorani's long-term research interest has been HVDC transmission systems and converter stations. During 6 years with Bonneville Power Administration before joining the Institute's technical staff in October 1974, he was responsible for commissioning the 850-mile Pacific NW–SW DC Intertie between northern Oregon and southern California. For nearly 11 earlier years, Hingorani held research and teaching posts at three universities in England. An electrical engineering graduate of the University of Baroda (India), he earned his MS and PhD in HVDC power transmission at the University of Manchester.

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Batteries don't store electricity; they store chemical energy, but the process is by no means loss-free. How fast, how often, how much, and how many times can various batteries be charged and discharged for leveling the peaks and valleys of utility system demand?

BEST for Batteries (page 20) notes the dedication of the new facility in the United States that will put together all the numbers on advanced battery performance, reliability, and economy in utility operations. The article is by Nadine Lihach, *Journal* feature writer; technical background came from William Spindler, EPRI project manager for battery testing and evaluation.

Spindler joined the EPRI staff in November 1976, having spent 13 years with the Naval Ordnance Laboratory at Corona, California, where he was head of the electrochemistry branch. Earlier, he was chief engineer of battery R&D with an ordnance manufacturer and worked for 7 years with the Atomic Energy Commission at the University of Chicago and at Los Alamos Scientific Laboratory. Spindler graduated in physics from Michigan State University. Just prior to his coming to EPRI, he spent 6 years in public health work, including graduate study at the University of Southern California and work with two agencies developing community health programs in California metropolitan areas.

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Distinguishing the stress behavior of relatively brittle and ductile steels is important for the designers and manufacturers of power plant pressure vessels and piping. Utility inspection criteria, repair and replacement guidelines, and various consequent costs in nuclear plant operation all devolve on the applied science of fracture mechanics.

Breakthrough in Fracture Mechanics (page 22) explains the basis for analyses sponsored by EPRI since 1975 and soon to bear fruit in new calculation methods for ductile fractures. Written by Nadine Lihach, *Journal* feature writer, the article draws from the research experience of Theodore Marston and Karl Stahlkopf of EPRI's Nuclear Power Division.

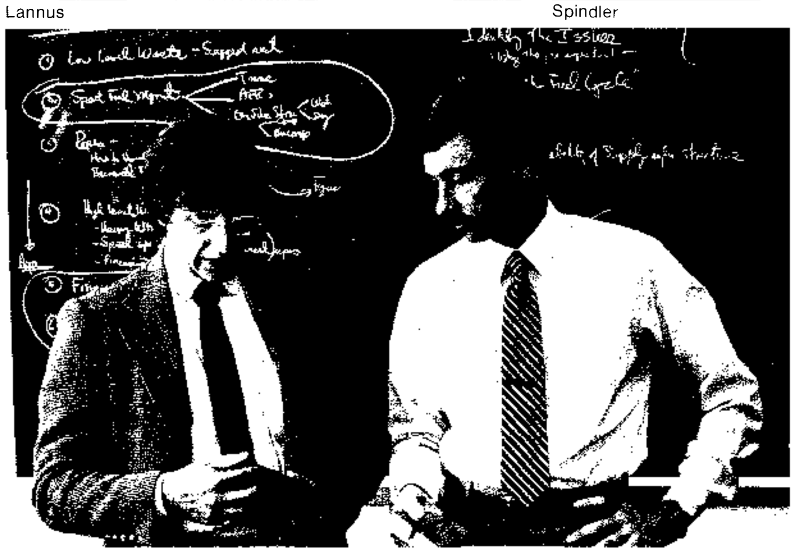
Marston joined EPRI in February 1976 after three years with Combustion Engineering, Inc., in materials testing and analysis at the company's Chattanooga, Tennessee, plant. His work involved both shop and field inspections of nuclear and fossil power plant components. Marston earned his BS, MS, and PhD in mechanical engineering at the University of Michigan between 1965 and 1972.

Director of the Systems and Materials Department for two years, Stahlkopf has been with EPRI since November 1973, specializing in pressure boundary technology. Before coming to the Institute, he was a research fellow for three years at the University of California at Berkeley, where he earned an MS and a PhD in nuclear engineering. Earlier, Stahlkopf was a naval officer for seven years, working on nuclear submarine propulsion and, during one year with the Chief of Naval Operations, as a technical consultant on advanced designs.

Hingorani

Lannus

Spindler

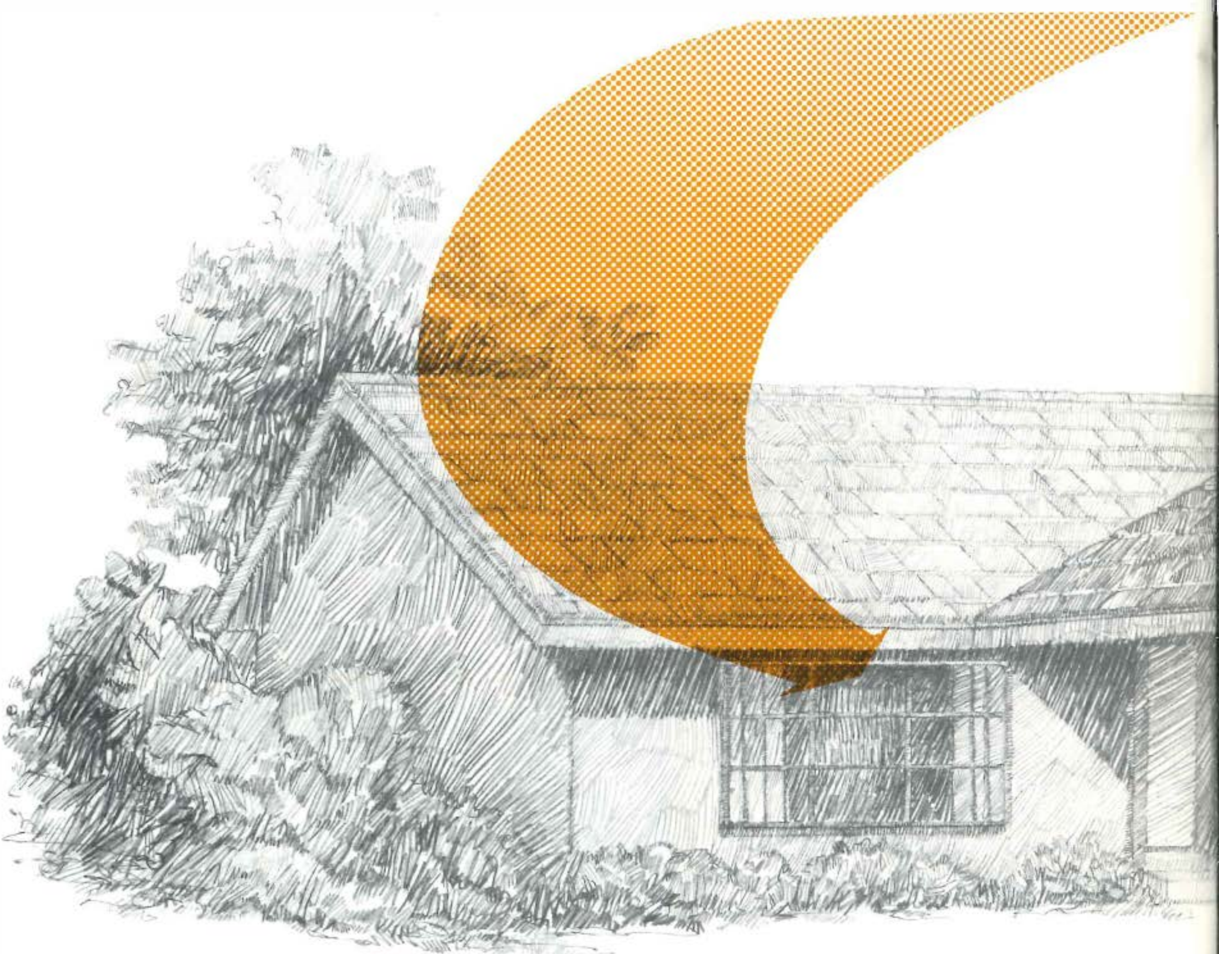


Marston

Stahlkopf

Much like a pump driving water uphill, the heat pump works against nature. It uses mechanical energy to transfer heat from a cool place to a warmer one. The heat pump concept was a scientific curiosity when first proposed by Lord Kelvin in the nineteenth century, but after surviving a shaky commercial debut during the 1950s, today the device looks like a strong contender in the residential/commercial space-heating market.

Resource conservation and efficiency are the main appeals. The heat pump can gather free low-grade heat that is always present in the environment, upgrade its temperature, and deliver it indoors for warmth and human comfort. The electrically powered heat pump, so far the only kind that is commercially proven, can save the oil and gas that would otherwise be used to fuel com-



DIRECTING HEAT FLOW

bustion furnaces. What's more, it can deliver more heat per unit of electricity consumed than traditional electric resistance heating.

Sales of electric heat pumps are currently running around half a million a year, a fivefold leap from the level that prevailed just before the oil embargo. Predictions are that deliveries will top one million by 1990. This rosy future depends on a number of contingencies, though, and not the least of them is living down the heat pump's dubious past.

The northern move

The first wave of commercial heat pumps grew out of post–World War II affluence in the South. With the postwar jump in disposable income, many consumers were no longer willing to tolerate the hot, sticky southern summers without some relief. Sales of room air conditioners took off, reaching a satura-

Heating and cooling versions of the heat pump are nearly identical, but the flow of the working fluid is reversed. Because the heat delivered indoors represents more energy than the electricity that runs it, the heat pump is the most efficient form of electric heating. With R&D improvements in efficiency and reliability, it's becoming competitive in a wider range of winter climates.

tion point of some 70–80% in certain areas.

The air conditioning boom paved the way for the heat pump because, in principle, the heat pump's heat delivery mode of operation is simply air conditioning in reverse. Air conditioning uses the mechanical energy provided by an electric motor to remove moisture and expel heat from warm indoor air to the outdoors; heat pump heating, in contrast, uses electricity to draw warmth indoors. It was natural for manufacturers to try to combine both functions in a single reversible device.

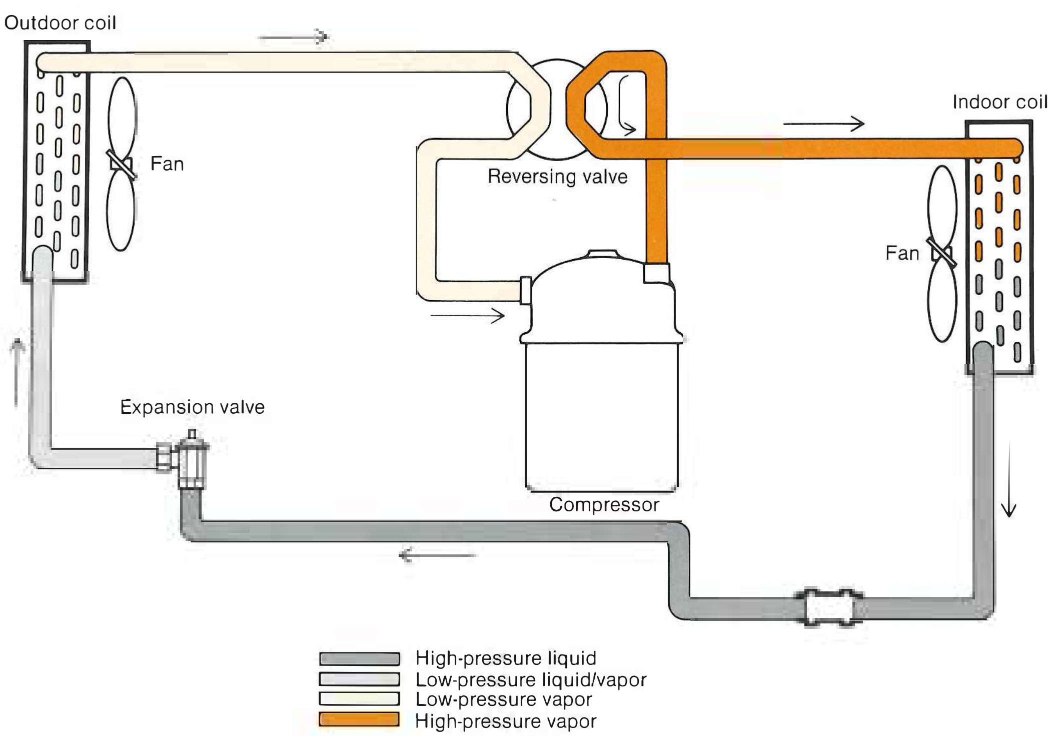
The early, unsophisticated heat pumps that were modified air conditioners hit substantial snags, however. Running such a device in the heating mode greatly increased the thermal and mechanical stresses on it, particularly if it had to cope with freezing outdoor temperatures or prolonged spells of cold weather. Equipment failures were the frequent result. When manufacturers attempted to carry the market for their first-generation reversible heat pump from the mild southern climate into the more rigorous northern climate, the heat pump met its Waterloo.

Thanks largely to the determination of a few manufacturers and support from the utility industry, the heat pump survived its debacle. Research moved forward, identifying and correcting problems. So manufacturers were ready with a new generation of greatly improved reversible heat pumps when the OPEC oil embargo handed the heat pump its second chance.

Oil shortages and cutbacks in natural gas allocations for new residential units, coupled with soaring oil and gas prices, nearly doubled sales of the resurrected heat pump in a single year. Overall, sales rose from a subsistence level of just under 100,000 in 1972 to a robust 550,000 in 1979. Current sales are slightly below that level because of lower housing starts and the crunch of high interest rates. The general direction of electric

For heating, the fluid begins as a low-pressure mixture of liquid and vapor. Absorbing low-grade heat at the outdoor coil, it vaporizes. The vapor is then compressed to high pressure and to a temperature greater than indoors. Transfer of this heat to the house interior subsequently cools and condenses the vapor to a liquid, still at high pressure. When it passes through the expansion valve, its temperature and pressure are drastically lowered and the fluid again becomes a liquid-vapor mixture.

HEATING MODE



pump sales over the next decade is expected to be up firmly.

The northern half of the United States, defined as the northern 29 states on the basis of cold weather statistics, still accounts for about 75% of the nation's total heat consumption. So this market is the prime target for expanding sales of the electric heat pump. Much of the research that has gone into improving heat pump technology since the 1950s has been addressed to the problem of delivering a product that can successfully cross the Mason-Dixon Line, a product that can handle the heavy heating loads and extreme temperatures typical of a northern winter.

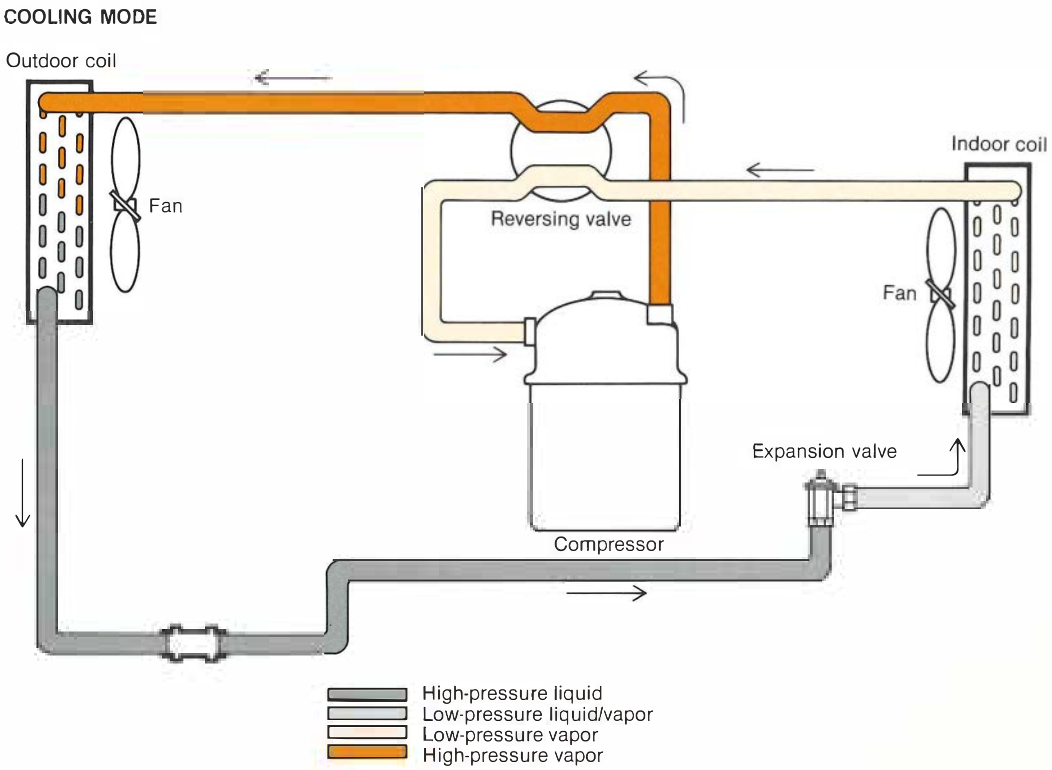
To understand the thrust of this research and how it can shepherd the heat pump's migration toward new markets, we need to know more about how a heat pump works.

How a heat pump works

The heat pump runs on an evaporation-condensation cycle, just like traditional air conditioners and refrigerators. A typical vapor-compression electric heat pump has several vital components: a working fluid, called the refrigerant, that circulates continuously in a closed cycle; a motor-driven compressor; a pair of heat exchanger coils, which can alternate in the roles of condenser and evaporator; and some form of expansion valve that can be used to control the pressure drop and hence the temperature change of the working fluid.

Take the heating process as an example. In winter, the heat exchanger coil located outside the house functions as an evaporator, absorbing low-temperature heat from the environment. This heat transforms the low-boiling-point liquid refrigerant within the coil to a vapor. The vapor passes to the motor-driven compressor, where it is compressed to a higher pressure and hence a higher temperature. The high-pressure, high-temperature vapor then enters the indoor coil, which functions as a con-

For cooling, the low-pressure mixture of liquid and vapor is vaporized at the indoor coil, then compressed to high pressure and temperature before flowing through the outdoor coil. As its heat is given up to the outdoor air, the fluid condenses to a liquid, which is further cooled by its passage through the expansion valve and return to the indoor coil as a cold, low-pressure mixture of liquid and vapor.



denser, turning the refrigerant vapor back into a liquid and releasing heat in the process. This is the heat that warms the interior of the house.

To complete the cycle, the liquid refrigerant proceeds through an expansion valve, which allows it to expand to a lower pressure and thus lowers its temperature. This is the state of the liquid refrigerant when it once again enters the outdoor evaporator. There it will absorb heat, vaporize, and begin another trip through the loop. The refrigerant within the closed loop is usually some form of fluorocarbon (most alternatives are too flammable or too toxic for general use).

Switching the heat pump from the heating mode to the cooling mode is done simply by switching the direction of the refrigerant flow. For summertime operation, the outdoor coil becomes the condenser and the indoor coil the evaporator. By condensing water vapor out of the circulated interior air, the heat pump can also dehumidify like a traditional air conditioner.

Measuring performance: COP and SPF

The heat pump's efficiency in accomplishing the heating (or cooling) requirement imposed on it is measured by its coefficient of performance (COP), the ratio of heat output to work input. The theoretical maximum COP of a heat pump can be calculated from thermodynamic principles.

$$COP_{heating} = \frac{\text{heat output}}{\text{work input}} = \frac{T_{high}}{T_{high} - T_{low}}$$

The high temperature is that of the heat sink; the low temperature is that of the heat source. Suppose that the temperature is 40°F (4°C) outdoors, and we want to warm a building to 70°F (21°C). In this case, the ideal COP would be 18, meaning the ideal heat pump would deliver 18 units of heat energy for every unit of electricity input.

$$\frac{70 + 460}{(70 + 460) - (40 + 460)} = 18$$

Note that the formula is based on temperatures expressed on the absolute (Rankine) scale, so 460° must be added to the Fahrenheit scale.

The equations show that the maximum heating performance of an ideal heat pump depends on the temperature difference between the low-temperature heat source and the high-temperature heat sink. The more the heat pump has to change the temperature of the heat it is taking in, the harder it has to work and the more electric energy it will need in order to pump heat from the colder to the warmer level.

But even under laboratory test conditions, no heat pump can approach this level of performance. The theoretical cycle on which the formula is based requires that all phases of the cycle be accomplished with a thermodynamically ideal working fluid and without friction, neither of which is attainable in practice. A number of real-world effects, ranging from the nonideality of working fluids, the need for fan power, and finite temperature differentials across heat exchanger surfaces to heat-robbing air movement and electric motor losses, cut the COP to 3, or even less, for most heat pumps under typical laboratory conditions.

Until recently, laboratory standard COP ratings were established with the heat pump operating at a steady state on constant source temperatures. In the field, where temperatures vary, the heat pump will typically experience energy losses from on/off cycling and the need to defrost the outdoor coil at lower temperatures. Both effects reduce the COP. The new DOE heat pump testing and rating procedures attempt to correct the standard ratings for these losses. Field performance in any given installation is also highly site-specific; it will depend not only on local source temperatures and on the heat pump design itself (there are some 85 separate models now available) but also on the insulation characteristics of the particular building and a host of related factors.

Capacity relative to heating and cooling requirements is especially important in determining the heat pump's field performance, and proper sizing is a challenge because the winter heating load and the summer cooling load are rarely equal. The average building in a temperate region uses its heating about four times as much as its cooling over a year's time. Further, the thermometer dips below 40°F (4°C) far more often than it rises above 100°F (38°C). So a heat pump working in winter must confront not only longer hours of operation but more extreme temperatures, which tend to degrade its COP.

The dilemma is that a heat pump large enough to handle all these winter demands is usually too large. If it is excessively oversize in proportion to the cooling load, it can produce a clammy feeling in summer because of inadequate dehumidification. And it will be uneconomic even for winter heating, as the costly extra capacity will be needed only on the two or three coldest days of the year. A good practice in colder climates is to provide sufficient capacity to meet the heating requirements of the building at least 50% of the time without oversizing excessively for cooling (not more than 30%). The balance of the time, then, electric resistance heating or an existing gas or oil furnace is required to supplement the heat pump.

Because a heat pump's performance will vary throughout a heating season and require supplementary heat, a yardstick is needed to gauge actual field performance. The seasonal performance factor (SPF), as it is called, measures the heating or cooling accomplished in a given season against the total work input by the heat pump and all auxiliary equipment.

$$SPF = \frac{\text{total output}}{\text{total energy consumed}}$$

The SPF is a better measure of the field performance of the heat pump than the COP because it takes into account the conditions that detract from the expected laboratory-rated COP. Whereas the rated COP of a heat pump can be 3 or more, a winter SPF of 1.5–2.1 is the range for most well-designed and properly installed air-source models operating in a northern climate. In a southern climate, SPFs can be even higher.

Tracking research

Research on upgrading heat pump technology focuses on ways to improve seasonal performance factors without sacrificing reliability or increasing costs too much. A major goal is to extend the heat pump's heating capacity to the lower temperature ranges, thus reducing or eliminating the need for backup heat, while protecting the mechanism from excessive stress.

Because the compressor is the heart of the heat pump, much research has begun there. Part of the problem is basic design. The compressor is meant to compress gases; liquid refrigerant flooding back into the compressor means trouble. Such liquid slugging not only increases the mechanical stresses on compressor components but also tends to wash out the oil the compressor needs for lubrication.

Winter temperatures in the range of 25 to 40°F (−4 to 4°C) cause frosting on the outside coil. One way to remove this frost, which impedes heat transfer and reduces COP, is to briefly throw the cycle into reverse, sending hot gases to the outdoor coil to melt the ice. But this sudden reversal can jolt liquid refrigerant back into the compressor.

Research on less stressful ways to accomplish the necessary defrost function is part of the effort to protect the compressor when operating in colder climates. The trick is to find alternatives that do not increase the energy and time required for defrosting (average 3–5 minutes) because longer defrost cycles can mean a less efficient heat pump.

Work on the heat exchanger also offers a chance for boosting heat pump performance and efficiency, especially in cold weather. Increasing the heat exchanger's surface area increases the system's capacity for drawing heat out of the outdoor air and discharging it indoors. But there are limitations to this approach. Besides costing more, larger coils mean an increased charge of refrigerant, which in turn can increase the probability of liquid slugging in the compressor. Improving fan motors and developing "smart" controls that can monitor both internal and external conditions and fine-tune the heat pump's responses provide additional technical opportunities in the effort to improve heat pump components.

A different approach to improving heat pump performance in cold weather is capacity modulation. What this means is an effort to keep the capacity of the pump matched to the ever-changing demands placed on it by fluctuating temperatures. The idea is that the heat pump should work hard only when it really needs to, thus saving energy as well as wear and tear on heat pump components. One method, long common for rooftop air conditioners in commercial buildings, is to use dual compressors, with the second one swinging into operation only when the first approaches full capacity. Another is a two-speed compressor, which is now available. And a third alternative that looks increasingly attractive is the continuously modulated, load-following heat pump that adjusts its capacity to even relatively small changes in heating or cooling needs.

Some of the most innovative and promising heat pump research now under way extends beyond the heat pump itself. This is the hunt for usable heat sources that are warmer than the outdoor air on cold winter days—sources that can boost the heat pump's heating performance by giving it a thermal head start (*EPRI Journal,* November 1980, pp. 53–55).

Leading candidates for such sources are groundwater and even the ground itself, which at 40 to 70°F (4 to 21°C) in winter are considerably warmer than the northern air. The main drawback has been uncertain rates of heat transfer, plus corrosion problems and questions about the purity, quantity, and disposal of the groundwater used as a heat source.

Solar assistance for heat pumps is another possibility, with solar-heated hot water serving as the heat pump's heat source. But so far, the capital investment required to harness the solar heat source makes it uneconomical in comparison with the standard air source, which still accounts for the vast majority of all residential/commercial heat pump installations.

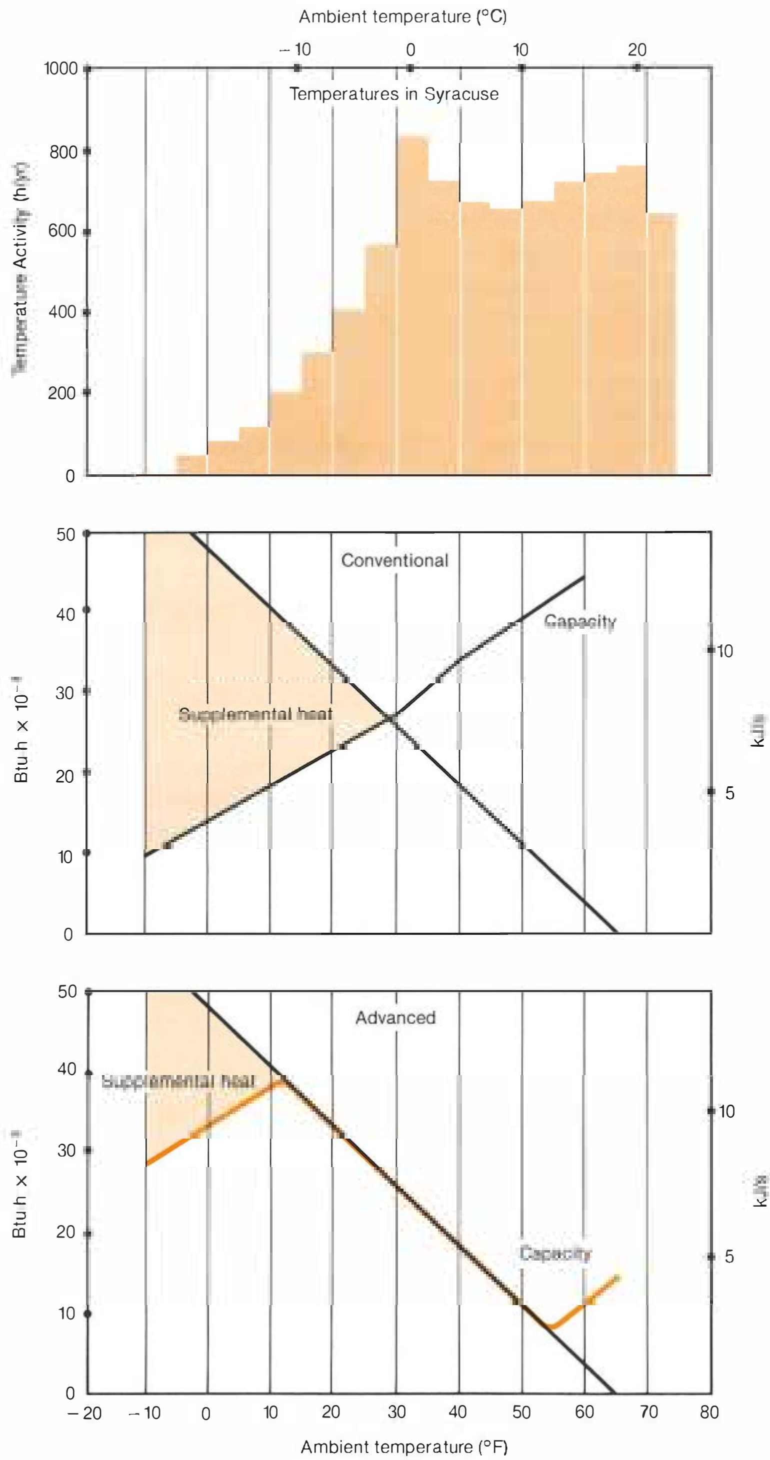
The research focus, then, falls in three major areas: efforts to improve the loop components, such as the compressor and the heat exchangers, both individually and in concert; efforts to adapt the heat pump's capacity to its varying load by capacity modulation; and efforts to provide it with higher-temperature heat sources for more efficient operation. Underlying these specific strategies is the basic drive to widen the potential uses for the heat pump by making it function better, especially in cold climates.

Mutual benefits

Both electric utilities and their customers stand to benefit from more widespread use of electric heat pumps. Heat pumps can raise the end-use efficiency of electric heating, with the potential to cut operating costs for both the supplier and the purchaser of that heating energy.

For utilities, a major benefit is to level loads (i.e., to smooth out the peaks and valleys of customer demand), which allows steadier and thus more efficient use of installed generating capacity. Roughly 70% of U.S. utilities experience their seasonal peaks in summer because of heavy air conditioning demand. For them, balancing this summer cooling load with an electric heating load in winter can improve seasonal load factors by making greater use of the capacity that is necessary to meet summer demand but otherwise may be idle much of the winter.

As outdoor temperatures drop, heat loss from a house increases, whereas output from a conventional heat pump decreases. Below the crossover point, supplemental resistance heating is required. In this example, the crossover point is 30°F; the histogram shows that even for such a northern climate as Syracuse, New York, the number of hours requiring supplemental heating are relatively few. Advanced heat pumps that continuously follow an increasing heat loss as temperature drops are being developed to reduce the need for supplemental heat and to improve efficiency and utility load factor.



Winter-peaking utilities now also face a growing demand for summer cooling, as even northern states experience hot summer days. In such areas the availability of an electric heat pump presents an opportunity to install an efficient new heating/cooling system in a single unit. The energy-efficient electric heat pump can aid winter-peaking utilities by shaving the demand peaks otherwise produced by heavy use of electric resistance heat.

In many cases, then, the electric heat pump offers utilities a chance to improve plant utilization and bring down overhead costs per kWh of electricity generated. And the customer shares in this benefit because holding down utility costs helps hold down electricity rates.

Recognizing the role of the electric heat pump in improving the industry's load factors, EPRI has launched an accelerated R&D effort in heat pump technology. The goal of this cost-shared effort is to help manufacturers develop heat pumps that will be more compatible with utility systems and provide effective heating/cooling for customers in a wide variety of climates. An integrated 4½-year series of projects is designed to help develop advanced heat pumps for residential and small commercial applications, as well as to analyze new heat pump concepts, systems, and applications and to field-test and evaluate new heat pumps arriving on the market.

Two such advanced models will soon be on the drawing board. One is a central unit scheduled for development, with field tests to begin in 1984, and the other is a room unit targeted for testing in 1983. Both are air-source models, designed to make effective use of outdoor air as a heat source even in northern winters. If successful in their development and field tests, these new heat pumps will be candidates for full-scale demonstration and commercialization in the mid-1980s—in time to meet the needs of the marketplace and the electric utility industry, as well as efficiency standards then in effect.

Granting the benefits of heat pumps for improved use of utility capacity, what would motivate an individual consumer to buy one? The advantages of the heat pump from the consumer's point of view fall into two general categories: those that apply to the use of electric heating in general and those that apply to the use of electric heat pumps in particular.

Electric heating of any type offers environmental advantages that are well known. It does not produce smoke, fumes, odors, or dust, as combustion furnaces often do. There is no danger of explosion. And electric heating can be used in rural areas that lie beyond the reach of most residential gas pipelines, areas where typically the only other choices are bottled gas, oil, or the rigors of coal- or wood-burning stoves.

Add to this the soaring cost of oil and gas, plus continuing uncertainty about future supplies, and the advantages of electric heating multiply. A sizable number of electric heating systems were placed in new construction during the mid-1970s because oil prices had soared, and new gas hookups were not available at the time. Gas supply problems have eased since then, but the threat of renewed cutbacks remains. Electric heating systems, in contrast, can run on electricity made from a great variety of domestic fuels.

Augmenting these advantages of electric heating are the unique benefits that an electric heat pump can offer. Most obvious is the heat pump's provision of heating and cooling in a single package. What's more, the device can be installed wherever it is most appropriate. Flexible in siting as well as in function, the typical air-source heat pump can be installed anywhere from basement to rooftop and takes up less space than the usual furnace and air conditioner heating-cooling combination.

The heat pump is also demonstrably more efficient than its electric alternative—traditional electric resistance heating. In the five years between 1973 and 1978, the percentage of all-electric new homes that featured heat pumps jumped from less than 10% to nearly 50%. A 1978 comparison of the two all-electric systems found that the heat pump used consistently less energy than a combined resistance heater–air conditioning system in all nine cities surveyed. Savings ranged from 11% annually in Houston to a whopping 47% in Seattle. The main reason for the greater savings in a cooler climate was that the heat pump consistently outperformed the electric resistance heater for heating purposes, but broke even with the air conditioner for cooling efficiency—a logical outcome, considering that the air conditioner itself is a form of heat pump.

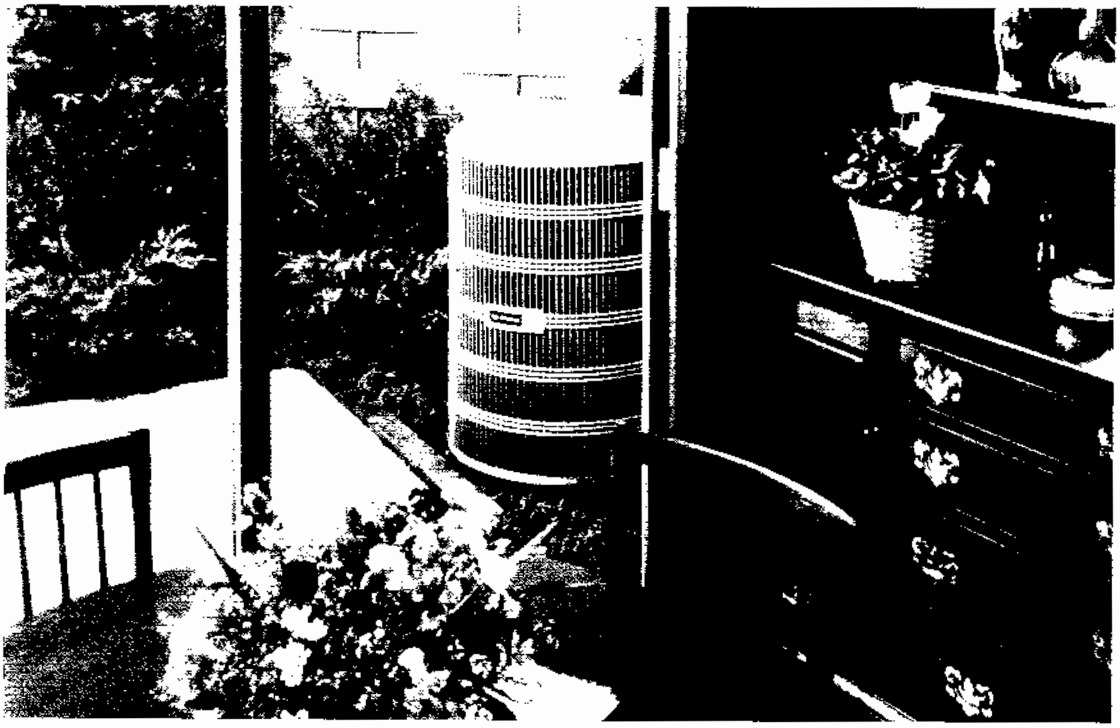
Buying an electric heat pump, then, can furnish the customer with electric heating in its most efficient form. This is the driving force behind a market that has already quintupled since preembargo days and is expected to double again in the coming decade. What course is this expanding market likely to follow?

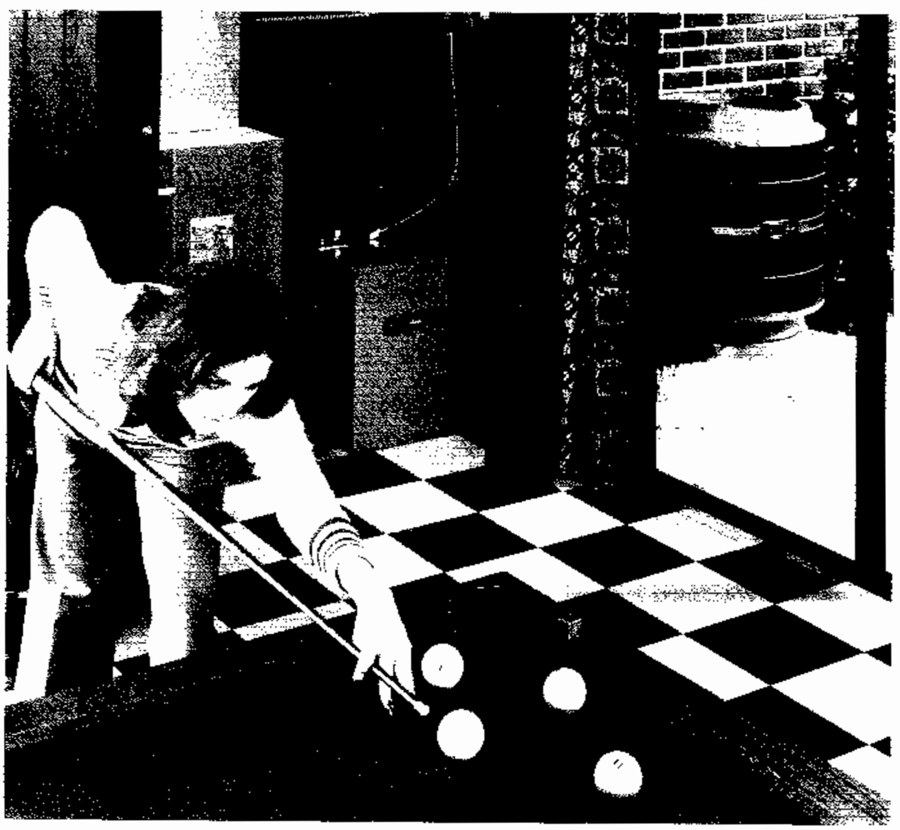
Market outlook

The future market for electric heat pumps is split between two possibilities: new construction and the retrofit of existing buildings. Both offer considerable potential. Today about 25% of new single-family homes are equipped with electric heat pumps for year-around space conditioning. Estimates are that this penetration will increase to nearly 30% by 1985 and to about 34% by 1990. At the same time, the center of the U.S. heat pump market is expected to continue its gradual shift northward as improved models demonstrate their ability to handle the northern winters.

The percentage of existing homes that have been retrofitted with heat pumps is considerably lower, probably less than 1%, although replacement statistics suggest the possibility of substantial sales. Every year, some two million air conditioners are sold, many to homes with existing oil or gas furnaces. Adding on

Escalating fuel costs have revived interest in the heat pump, which can significantly raise the end-use efficiency of electric heating. Many variations are now on the market. Today, roughly 25% of new single-family houses are equipped with electric heat pumps for year-round space conditioning; and this penetration is expected to climb to 33% by the end of the decade. The major research goal is to extend the heat pump's heating capacity to lower temperature ranges in order to penetrate more northern climates.





electric heat pumps to these homes would roughly triple heat pump sales from their present level of about half a million per year.

Realistically, the retrofit market is not that large because of physical constraints imposed by the old-fashioned duct systems in many existing homes. A central heat pump unit needs a wide duct system of the sort designed for central air conditioning. And the ducts should be insulated. Most older homes fail to meet these criteria, so expensive ductwork would have to be added to the $3000–$3500 purchase price of an installed typical three-ton home heat pump.

The exception is the room heat pump unit, which, like the room air conditioner, can be installed in virtually any residential or commercial space. EPRI's work in developing a new, high-efficiency room model is directed specifically toward tapping this retrofit market.

Besides the air-source models, a number of more exotic configurations are possible. In large commercial buildings, for example, the air in the core of the building itself may be a better heat source than the outside air. Rather than waste the heat given off by office lighting, computers, and the office workers themselves by exhausting it through the ventilation system, an internal built-up heat pump system can transfer it to water that carries the heat outward to warm the cooler offices on the perimeter of the building. Heat pumps can also be used with combustion furnaces in add-on hybrid arrangements. Or they can be combined with boilers and cooling towers to provide simultaneous heating and cooling in different parts of multiunit complexes. The possibilities are many and growing, especially with the development of new water-source and ground-source units. But the standard air-source units, most of them geared for central installation, still make up most of today's heat pump sales in the residential/commercial market.

Where this market will go in the future is by no means certain. Estimates place potential electric heat pump sales at well over a million units a year by the end of the decade, with units purchased for new construction outnumbering the retrofit units by a ratio of roughly two to one. The actual outcome, however, will depend on a number of factors that are not entirely predictable.

First and most obvious are uncertainties surrounding the price and availability of oil and gas. These are the factors that gave the electric heat pump its second chance in the mid-1970s, and they will continue to affect its future. If, as expected, the prices of oil and gas for home heating continue to escalate faster than the price of electricity, it will give the electric heat pump a sustained market lift. Renewed cutbacks in oil or gas availability could have an even more pronounced effect because they would once again leave consumers with little choice but to opt for electric heating.

Consumer acceptance is another critical area, especially in light of the heat pump's checkered history. The current generation of electric heat pumps seems to have solved the reliability problems that plagued older models, but another well-publicized rash of failures could dampen market projections. On the positive side, however, today's consumers are more conservation-oriented than those in the 1950s, so the heat pump's ability to tap free energy from the environment is a powerful marketing plus.

Tighter insulation requirements should also benefit the market because they will allow smaller and hence less-expensive heat pumps do an adequate job of heating and cooling buildings. The less these new heat pumps cost, the more people can afford them. So sizing down the technology can be expected to broaden the market.

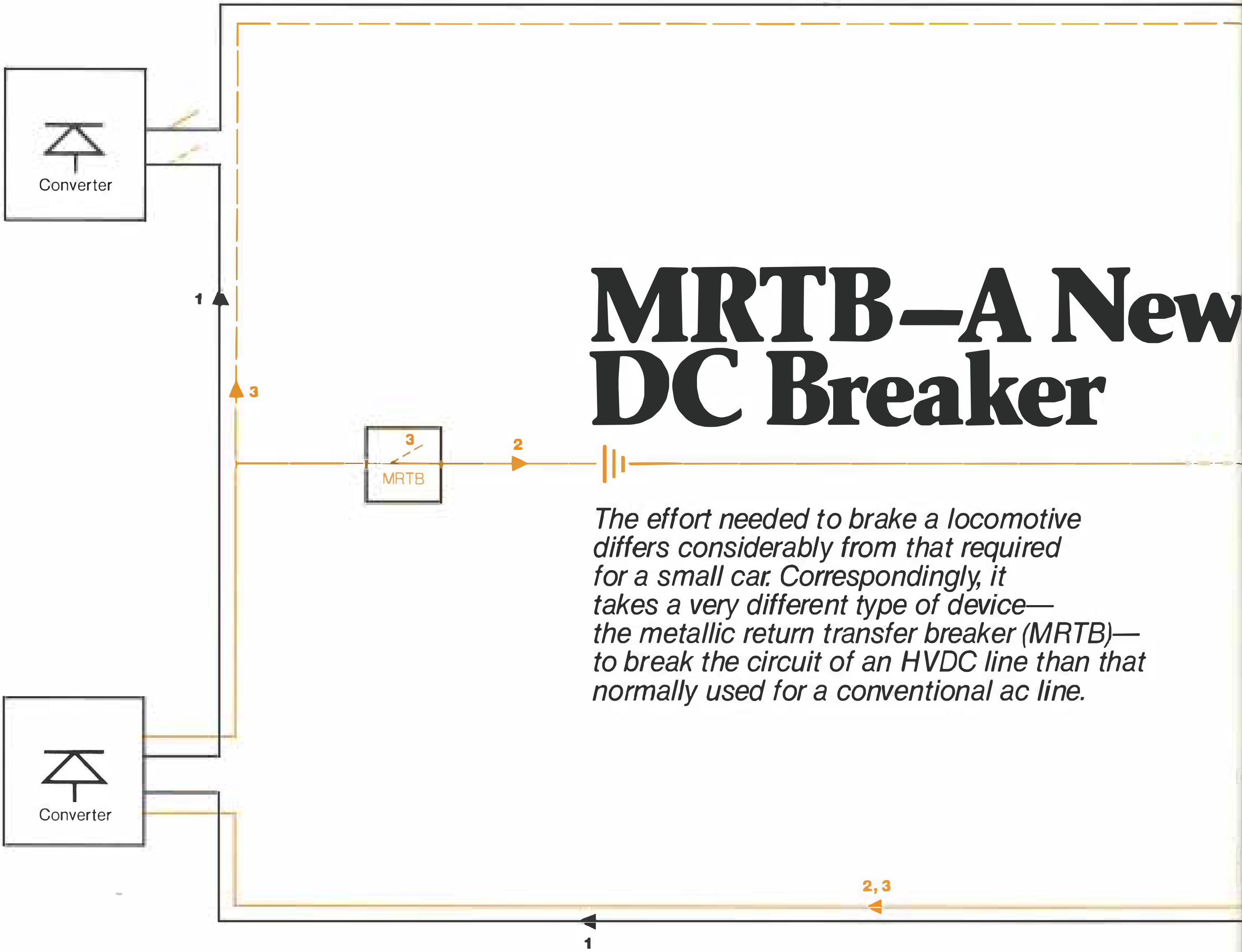
Washington could further promote the heat pump's prospects by making it eligible for tax credits and other federal energy-saving incentives. A 1978 study carried out by researchers at Oak Ridge National Laboratory projected heat pump energy savings at 1.5 quadrillion (1.5×10^{15}) Btu and $640 million by the year 2000. Recognizing the heat pump as an energy conservation tool—along with solar panels, weatherstripping, and storm windows—would go a long way toward defraying the cost of heat pump installation and making it affordable for a greater number of potential purchasers.

Then too, purchasers can look forward to better product backup than they've had in the past. Better warranties are available on the new models, and better service networks have developed to deliver the promised service. There are about 50 companies manufacturing heat pumps in the United States today, in contrast with the 32 or so that were operating in 1975.

The outlook is for heat pump purchases to grow in a pattern that roughly parallels the still-growing demand for air conditioning. The South, cradle of the air conditioner, already houses more than half of the nation's heat pumps. The real growth potential is in the North and the West, where consumers eyeing air conditioning for the first time can now buy heating in the same package. If heat pump research continues its progress toward reliable, economic heating performance even in very cold regions, then a major obstacle that tripped up the heat pump in the past and blocked its market expansion will have been removed.

The heat pump concept is not new; changing conditions have brought it to the fore. What it offers is a chance to use electricity for space heating more efficiently than previously possible. This represents a substantial stride toward streamlining a major energy use—one that accounts for about half our home energy consumption every year—in a way that can also reduce the nation's reliance on scarce fuels. ■

This article was written by Mary Wayne, science writer. Technical background information was provided by Arvo Lannus, Energy Management and Utilization Division.



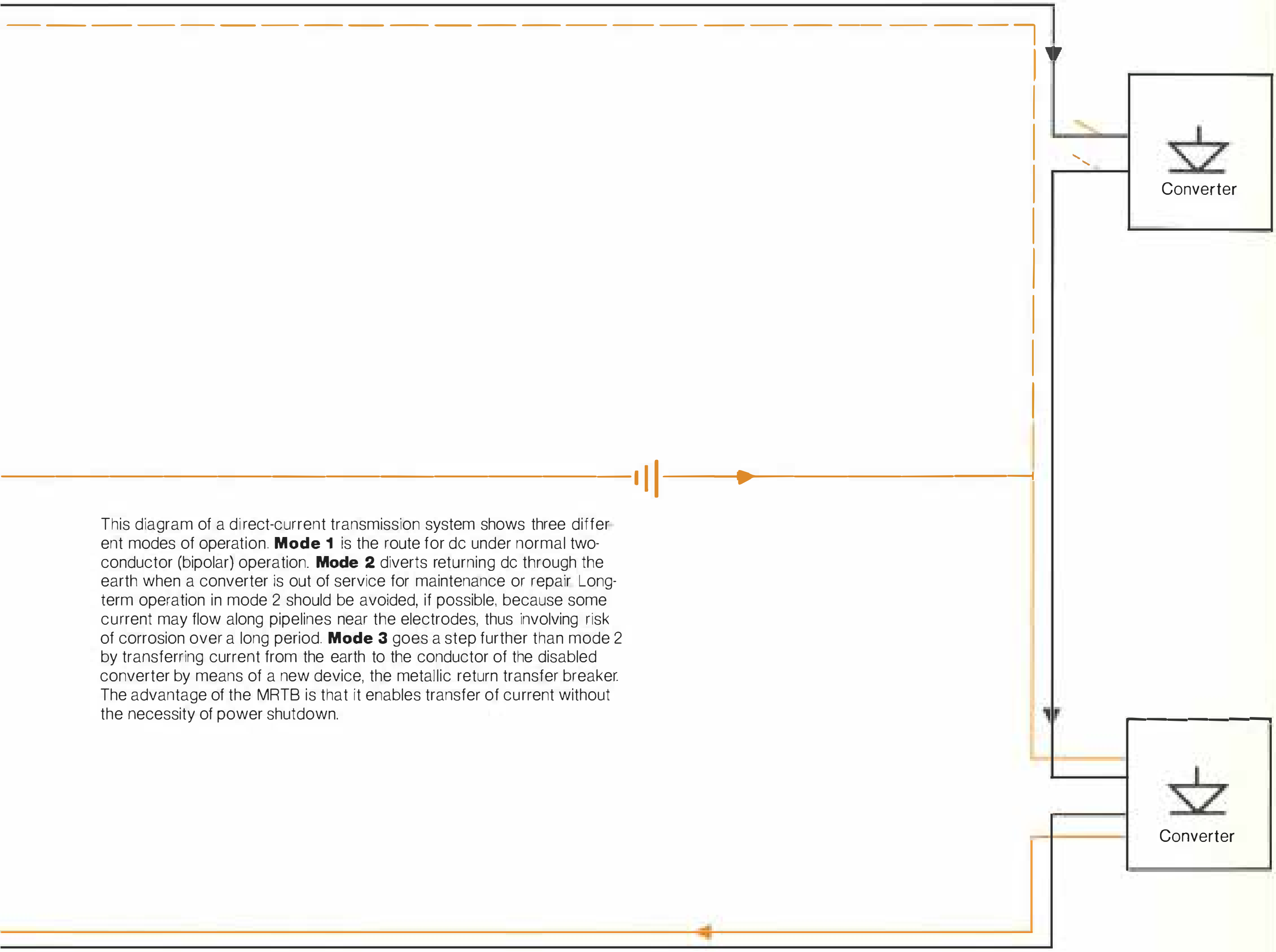
MRTB—A New DC Breaker

The effort needed to brake a locomotive differs considerably from that required for a small car. Correspondingly, it takes a very different type of device—the metallic return transfer breaker (MRTB)—to break the circuit of an HVDC line than that normally used for a conventional ac line.

Popularity of high-voltage direct current (HVDC) transmission systems is growing for many technical and economic reasons. Improvement is steady in the design and reliability of dc systems—and in the net cost, too, despite inflation. Many new projects are under construction or are being planned in the United States and other countries throughout the world.

In power transmission systems, the firm power requirements of the system are an important consideration. *Firm power* may be defined as the power that can be delivered should any one terminal or line of the system be disabled. To ensure firm power capabilities in ac lines, it is often necessary to install parallel, three-conductor transmission lines and additional circuit-breaking equipment. With dc transmission, substantial firm power is ensured in a simple bipolar, or two-conductor, scheme. If the insulation of one conductor is damaged or if converter equipment supplying one conductor (one pole) is out of service for maintenance or repair, more than 50% of the power can still be transmitted by using the earth to provide the return electric path for the functioning conductor.

Although operation of the dc system in this earth-return mode for long periods is satisfactory from the standpoint of the utility system, it can have side effects on gas or oil pipelines that lie within a few miles of the system electrodes. Pipelines can act as conductors for the current returning via the earth, and when current exits a pipeline, it can, with repeated occurrences, cause disbonding of the metal (corrosion). Operation of a system using earth as the return path, therefore,



This diagram of a direct-current transmission system shows three different modes of operation. **Mode 1** is the route for dc under normal two-conductor (bipolar) operation. **Mode 2** diverts returning dc through the earth when a converter is out of service for maintenance or repair. Long-term operation in mode 2 should be avoided, if possible, because some current may flow along pipelines near the electrodes, thus involving risk of corrosion over a long period. **Mode 3** goes a step further than mode 2 by transferring current from the earth to the conductor of the disabled converter by means of a new device, the metallic return transfer breaker. The advantage of the MRTB is that it enables transfer of current without the necessity of power shutdown.

should be minimal. And a way has been found to accomplish this—the metallic-return mode.

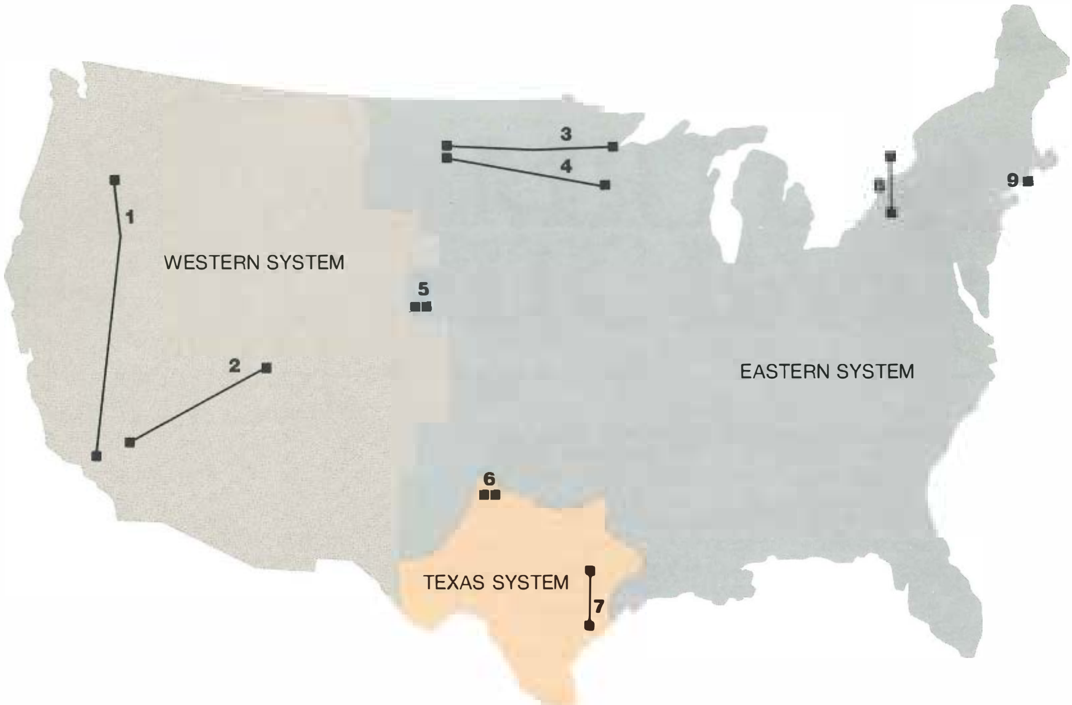
Most instances of dc lines forced to operate in the earth-return mode are caused when terminal equipment is out of service or when one conductor sustains partial damage to its insulation. In these cases, the unserviceable line can substitute for the earth as a path for return current, thus avoiding potential corrosion of nearby pipelines.

When commercial operation began on the 850-mile HVDC Pacific Intertie Line, which runs from The Dalles, Oregon, to Sylmar, near Los Angeles, it became clear that to minimize objections to the extended use of the earth to carry dc, operation with earth return should be limited to short periods (less than a few hours at a time) and this limitation should hold not only for this intertie but also for most future interties in the United States. Interim means were devised to operate this intertie in the metallic-return mode: opening the earth-return path at one end and passing the return current through the unused conductor instead of the earth. However, transfer from earth return to metallic return and vice versa could only be done at no load; that is, for each transfer, power transmission was shut down for 30–60 minutes, often at such critical times as peak demand periods. It became necessary, therefore, to develop a dc breaker that would do this job on load (i.e., without power shutdown).

The key requirement of such a dc breaker is to break a current of 2000 A against a voltage of 80 kV. At full load, the breaker has, in fact, to absorb 7–8

DC PROJECTS IN THE OFFING

HVDC projects in the United States in operation or proposed for construction in mid-1982. In some projects, dc is used for efficiency in long-distance transmission. In other projects, dc provides power interconnection where an ac connection is not feasible for reasons of possible system instability and the need for independent control of each system.



1 HVDC Pacific Intertie 1440 MW (proposed extension to 1800 MW)
2 Intermountain Power Project 2400–4000 MW (proposed)
3 Square Butte 500 MW
4 Cooperative Power Assoc.-United Power Assoc. 1000 MW
5 Tri-State G&T Assn., Inc. (Stegall) 100 MW
6 Oklaunion 200 MW (proposed)
7 Walker-South Texas Project 500 MW (proposed)
8 Lake Erie Cable 1200 MW (proposed)
9 EPRI Prototype 100 MW

Greater system stability and reliability can be provided by dc transmission because power flow is less influenced by changes in voltage and frequency. Thus dc is becoming the preferred choice where there are restrictions on widening rights-of-way, geographic reasons for underwater connections, or difficulties in system interchange between regions.

This year six or seven dc projects are being discussed in the United States. The largest now being planned is the intermountain power project, which will carry electric power from a coal-fired generating plant in Utah to Los Angeles. Dc is expected to ensure greater stability and reliability with fewer right-of-way requirements than ac transmission.

Another project is a dc underlake cable interconnection that will enable General Public Utilities Corp., New Jersey, to buy power from and interchange power during emergencies with Ontario Hydro in Canada. If ac transmission were used, an overhead line would have to be built around Lake Erie, a distance of about 150 miles. But with dc, the underlake cable would be only 40 miles.

Yet another example is the move taken by Central and South West Corp., Houston Lighting & Power Co., and Texas Utilities Co. to install two HVDC links between the Texas interconnected system, the Electric Reliability Council of Texas, and the Southwest Power Pool. Although SWPP is interconnected with the eastern U.S. power system, ERCOT is not, and in a recent decision, the utilities involved chose dc as a more "forgiving" transmission mode for interregional power exchange. □

MJ (megawatt-seconds) of energy with each transfer.

In cooperation with Bonneville Power Administration, Portland, Oregon, EPRI undertook to develop such a breaker—the MRTB. It was to be demonstrated on the HVDC Pacific Intertie, which represents the most difficult breaker application in the United States because of the long line and consequent buildup of voltage (high inductance), plus associated energy that has to be dissipated in the breaker to transfer the current in the event of a fault.

The original MRTB was constructed by Hughes Research Laboratories. In this first design, the circuit breaking was accomplished by opening the in-line oil circuit breaker (OCB) and simultaneously turning on a device called the cross-field tube (XFT) by applying a magnetic field. The arc voltage of the OCB caused the current to be transferred to the XFT. Once this happened, the XFT was turned off by removing the magnetic field. The resultant high arc voltage of the XFT then caused the current to be transferred to a capacitor.

A capacitor can be compared to a spring in that it can absorb sudden surges of voltage. Once the current is transferred to the capacitor, the capacitor voltage rises quickly to a level at which an adjacent zinc oxide resistor (supplied in this design by General Electric Co.) becomes conductive. The current is finally diverted to this resistor, which limits the voltage to 80 kV and absorbs the energy. Eventually, the resistor ceases to conduct and the steady-state voltage across the MRTB decreases to the 40-kV voltage that exists in the metallic-return path.

This original design successfully passed laboratory tests and was installed at BPA's Celilo Converter Station at The Dalles, Oregon, which is the northern terminal of the HVDC Pacific Intertie. (A breaker is needed at only one terminal.) Field-testing at 300 and 600 A passed without mishap, but during the 1200-A test the in-line OCB exploded. It is thought that a test lead failed and caused a short circuit across the MRTB. However, the damage to the OCB gave rise to doubts about its suitability for this function. At this point, work on the MRTB was halted until the cause of failure was found and the problem solved.

It so happened that while the initial MRTB work was in progress, a switching device was being developed at Westinghouse Electric Corp. for another application. This device—an ac fault current limiter—incorporates a vacuum switch with special internal contacts: an external magnetic field causes high arc voltage to be developed after the contacts of the vacuum switch are opened. Although this project was only at the halfway point, it was realized that even at the unfinished stage, this device was capable of performing the switching function for the MRTB by replacing both the in-line OCB and the XFT, thus providing a much simpler and more reliable design.

During normal operation of this simpler MRTB, continuous current is carried by the internal contacts of the vacuum switch. When the circuit must be interrupted, these contacts are parted and a transverse magnetic field is applied. The resultant high arc voltage causes the dc to be forced initially into the capacitor and then into the resistor, as in the first version of the MRTB. As before, when the resistor has absorbed the energy of the circuit, it ceases to conduct and interruption is complete.

A decision was made to temporarily divert some of the effort on the vacuum switch from its role in ac fault current limiting to its new MRTB application. By July 1980 a completely packaged and laboratory-tested device was delivered to BPA by Westinghouse. BPA modified the control and monitoring system, developed a plan for field tests, and designed and installed the test instrumentation at its Celilo Converter Station.

The full-scale field tests were an unqualified success. In October four tests were made from 200 to 1700 A with power flow from Celilo to Sylmar. Then the power flow was reversed and six additional tests were made up to 1700 A, which was the maximum system current allowed at that time when operating in the monopolar, or one-conductor, mode. In addition to establishing that the MRTB would perform exactly as anticipated with no deterioration evident, the speed and consistency of the circuit-breaking function indicated reliability and an adequate safety margin. The control and instrumentation system was also found to be satisfactory.

The MRTB is now permanently installed at Celilo, where it will undergo a year of field trials. It is being used to switch the HVDC Pacific Intertie into the metallic-return transfer mode when required. So far these in-service trials have been successful and the MRTB has enhanced the firm power capabilities of this system by removing the need to temporarily interrupt power flow to achieve the switching function.

It is worth pointing out that this is a true dc breaker and can be used as such for breaking a current of 2000 A against a voltage of 50 kV. With a high-speed disconnect switch in series and high insulation to ground, this breaker (in coordination with converter control) can also be used to isolate faults on a multiterminal high-voltage dc system.

The development of the MRTB provides dc transmission systems with an option of an advanced switching technique. In addition, it demonstrates the synergism that often results from seemingly unrelated research projects that are brought together through the teamwork of manufacturers, utilities, and EPRI. ■

Further reading

Narain Hingorani. "Monopolar Metallic-Return Operation of Long-Distance HVDC Transmission Systems." In *IEEE Transactions*, PAS-93, March-April 1974, pp. 554–563.

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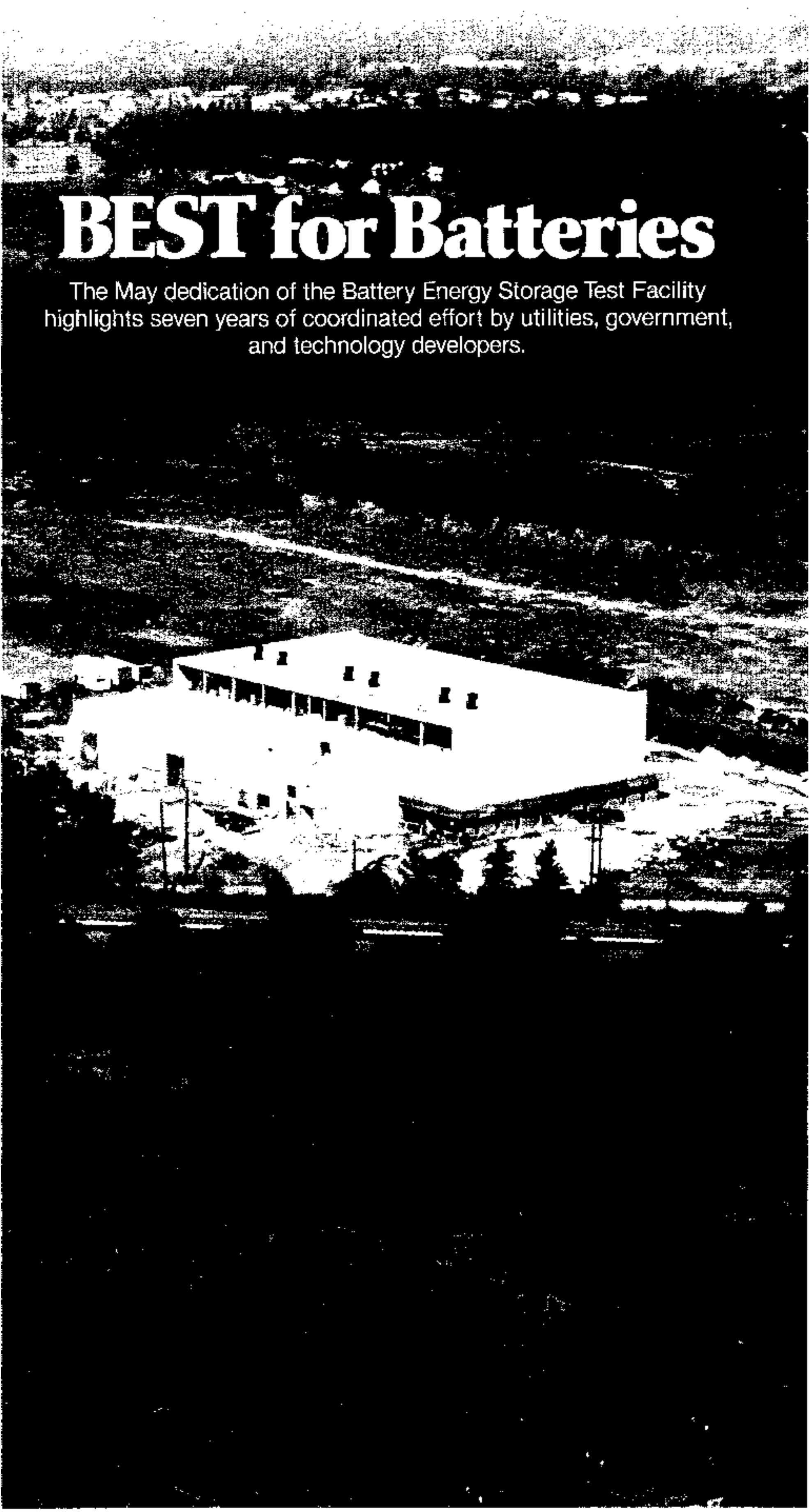
This article was adapted by Jenny Hopkinson from a paper by Narain Hingorani, Electrical Systems Division, and Joseph Porter, Washington Office.

BEST for Batteries

The May dedication of the Battery Energy Storage Test Facility highlights seven years of coordinated effort by utilities, government, and technology developers.



Lifting a new battery energy technology out of the laboratory and into the major new commercial application of energy storage service on electric power systems is a feat no one developer can expect to accomplish singlehandedly. The technical and financial risks involved in the transition are too imposing. But when developers share the risks with utilities and government, as they have at the Battery Energy Storage Test (BEST) Facility, Hillsborough Township, New Jersey, commercialization is closer at hand.

Seven-year effort

This month's dedication of the $17 million BEST Facility punctuates seven years of closely coordinated efforts. In 1974, when the OPEC oil embargo underscored the nation's unhealthy reliance on imported oil, utilities and the government knew that alternatives to oil-fired peaking units would have to be developed as quickly as possible. Advanced batteries were one likely candidate. Batteries can chemically store the relatively inexpensive energy produced by coal or nuclear baseload power plants during off-peak periods and transform that energy back into electricity when demand peaks.

Yet because of the unpredictabilities and risks associated with introducing new technologies into utility service, the route to battery commercialization was uncertain. If this potentially attractive alternative to meeting peak demand was to be speedily deployed by electric utilities, early evaluation of the candidate battery systems under development was required on a scale that would instill confidence. Because any evaluation of batteries on this multimegawatt scale requires extensive and costly equipment, close cooperation was necessary.

Meetings between EPRI, utility representatives, Argonne National Laboratory, and the Atomic Energy Commission (later ERDA and now DOE) suggested a solution: a national center for the testing of advanced battery and power converter systems for commercial utility service. This independent facility would verify system characteristics and performance in an actual utility environment. Utilities could thereby secure performance data on the storage battery systems they needed; the federal government could further the national policy of energy independence; and developers of batteries and power converters could acquire the information necessary to perfect new battery technologies for commercial service. This one national facility would avoid numerous, partially redundant, almost prohibitively expensive individual test facilities, each serving a different battery type and manufacturer.

In 1975 ERDA issued a request for proposals from utilities to establish just such a facility. In 1976 New Jersey's Public Service Electric & Gas Co. signed on as host utility and prime contractor. By 1977 construction of the BEST Facility had started, with EPRI, DOE, and PSE&G sharing the costs—the first such major three-party venture.

The BEST Facility itself is now essentially completed, according to EPRI Project Manager William Spindler. Startup and acceptance testing of the basic facility has begun with the 1.8-MWh lead-acid station battery supplied by C & D Batteries and installed in one of the facility's test bays. The facility includes provision for two other test bays (the first of these to be completed in early 1982), space for three ac/dc power conversion systems, switchgear, instruments, and control systems. Additional switchgear, power factor correction capacitors, and power transformers are located outdoors. Battery system control and monitoring is achieved through a computerized process control system based on programs used by utilities for generating plant control and central load dispatch. A remote data access system will make on-line and stored data available on command.

At the facility, developers will be able to test batteries that store from 1 to 10 MWh of energy and can be discharged at up to 2 MW. Three phases of test services will be offered to verify system design parameters, assess performance characteristics, and demonstrate operation under realistic utility conditions. A team from PSE&G, augmented by technical staff from the developers, will carry out all tests at the site and then report and interpret the results.

By the end of 1981 acceptance tests of the basic BEST Facility will be completed. Meanwhile, the facility's second test bay is being readied for its first test of an advanced battery system, most likely the prototype zinc chloride system being developed by Energy Development Associates, a subsidiary of Gulf+Western Industries, Inc. Before the actual testing can begin, the zinc chloride battery system must be integrated with the test facility. By 1982 the necessary modifications to the facility's second test bay, computer systems, and electrical systems should be completed and the battery system installed. A two-year test program can then begin. The battery developer will be responsible for the installation, maintenance, and decommissioning of its system. Testing costs will be shared by EPRI and DOE.

Future tests

After the zinc chloride battery system, the next system to be tested may be the sodium-sulfur (beta) battery or the lithium–metal sulfide batteries. Zinc bromide and Redox systems are future candidates. Although up to three batteries can be tested simultaneously, each battery system presents different technical evaluation issues and will have to be carefully integrated into the BEST Facility. Test bay modifications can take from 12 to 36 months.

To keep testing programs consistent, guidelines have been established for all candidate battery systems. Detailed individual test plans will be drafted by equipment developers in conformance with these guidelines, then battery and converter developers will work hand-in-hand with facility staff on detailed test procedures. The BEST Facility Developer Users Group, composed of battery and converter developers, has been helping to prepare these guidelines.

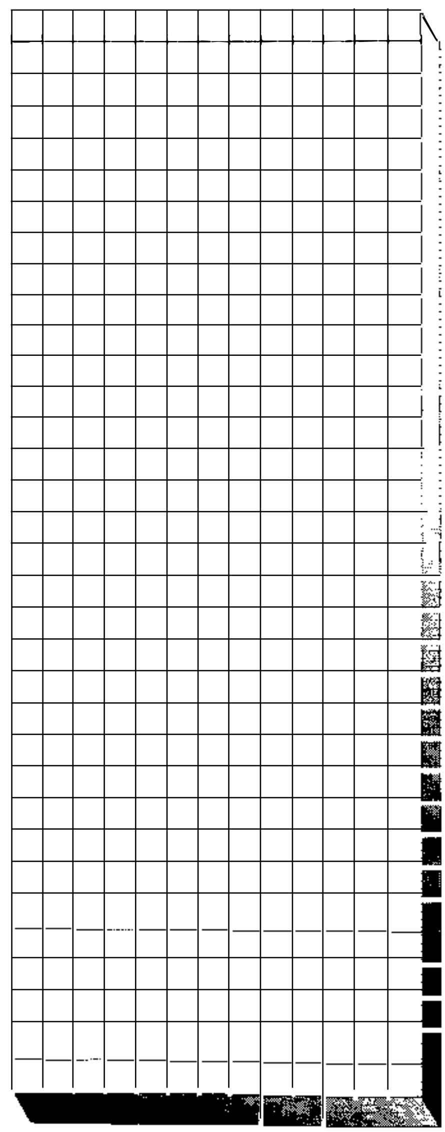
Within just seven years, the facility has become the main focus for potential users, developers, and funding agencies as they debate the issues surrounding the future of batteries in electric utility service. "The BEST Facility is positive proof that government and the private sector can work together to identify important requirements and opportunities for new energy technologies and then team up to meet them," concludes Fritz Kalhammer, director of EPRI's Energy Management and Utilization Division. Through the BEST Facility and through cooperation, battery systems on utility grids may be switched on during the 1980s. ■

A 1.8-MWh lead-acid battery for testing equipment at the BEST Facility.

This article was written by Nadine Lihach. Technical background information was provided by William Spindler, Energy Management and Utilization Division.

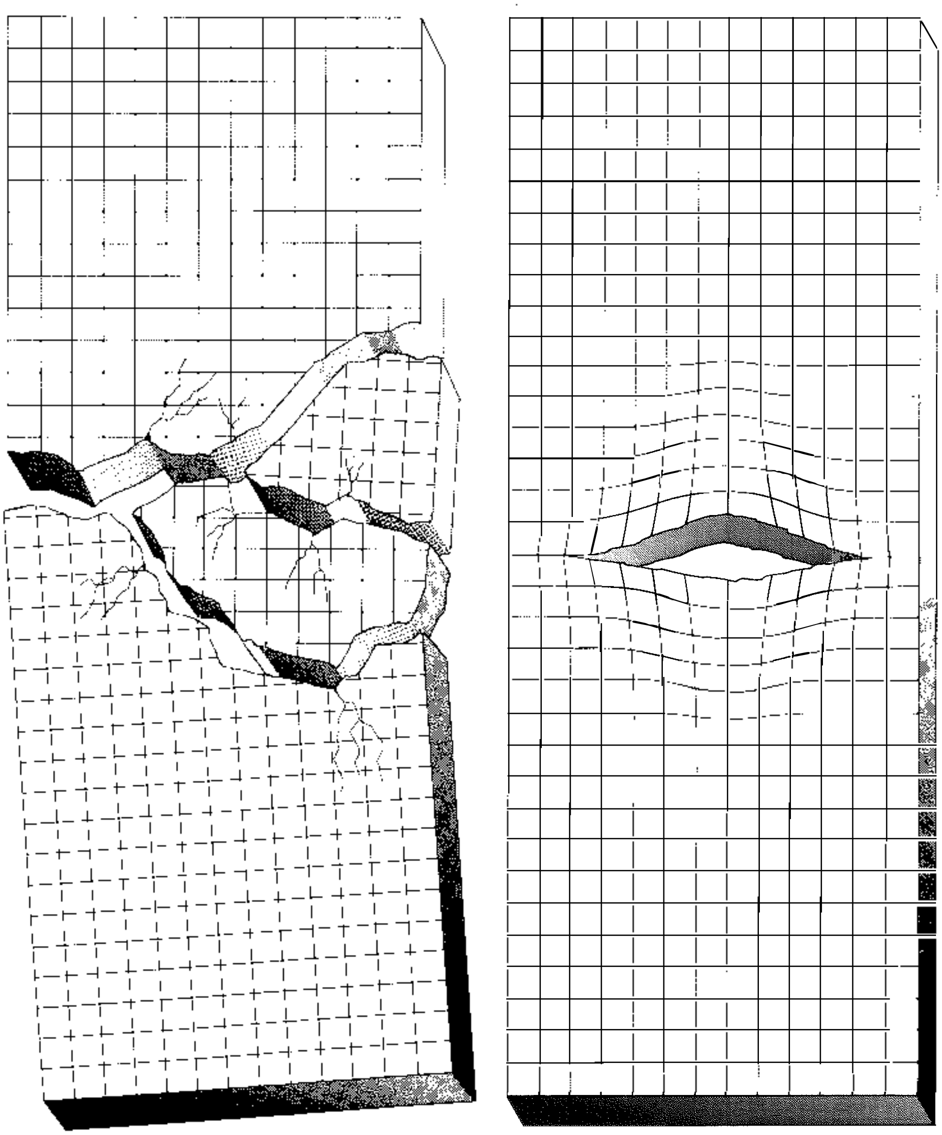
Breakthrough in

Fracture mechanics techniques that can describe the complex behavior of ductile materials are now becoming available. These advances can result in substantial savings in operating and maintenance costs at nuclear power plants.



Metal **(1)** can fail in different ways. One extreme is a brittle fracture **(2)**, where the material fails abruptly, almost like glass. The other extreme is a ductile fracture **(3)**, where the material deforms significantly before failure, absorbing large amounts of energy and growing slowly and stably. The guidelines used today to predict when a material will fail assume a brittle fracture, but recent research confirms that these guidelines are conservative when applied to the ductile materials used in the piping and pressure vessels of a reactor's pressure boundary. The use of appropriate ductile fracture mechanics methods may secure a longer service life for many plant components.

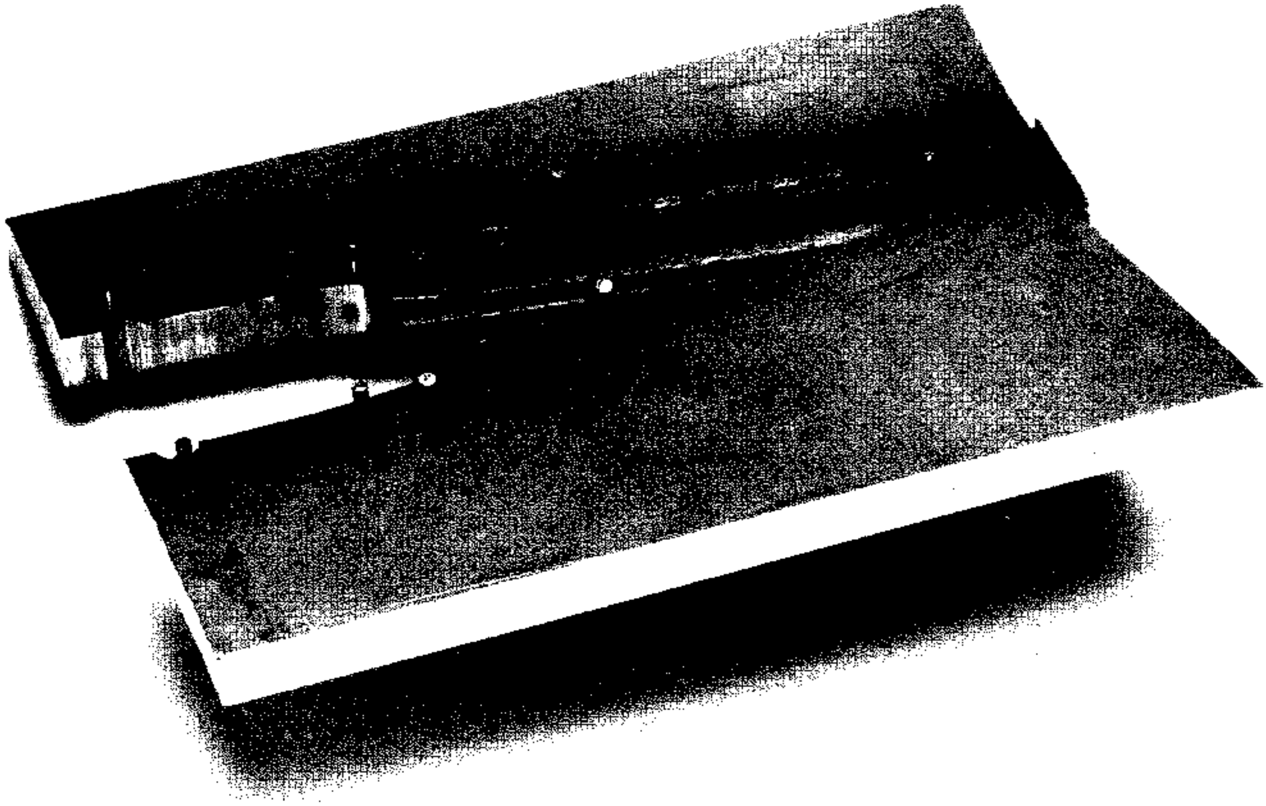
Fracture Mechanics



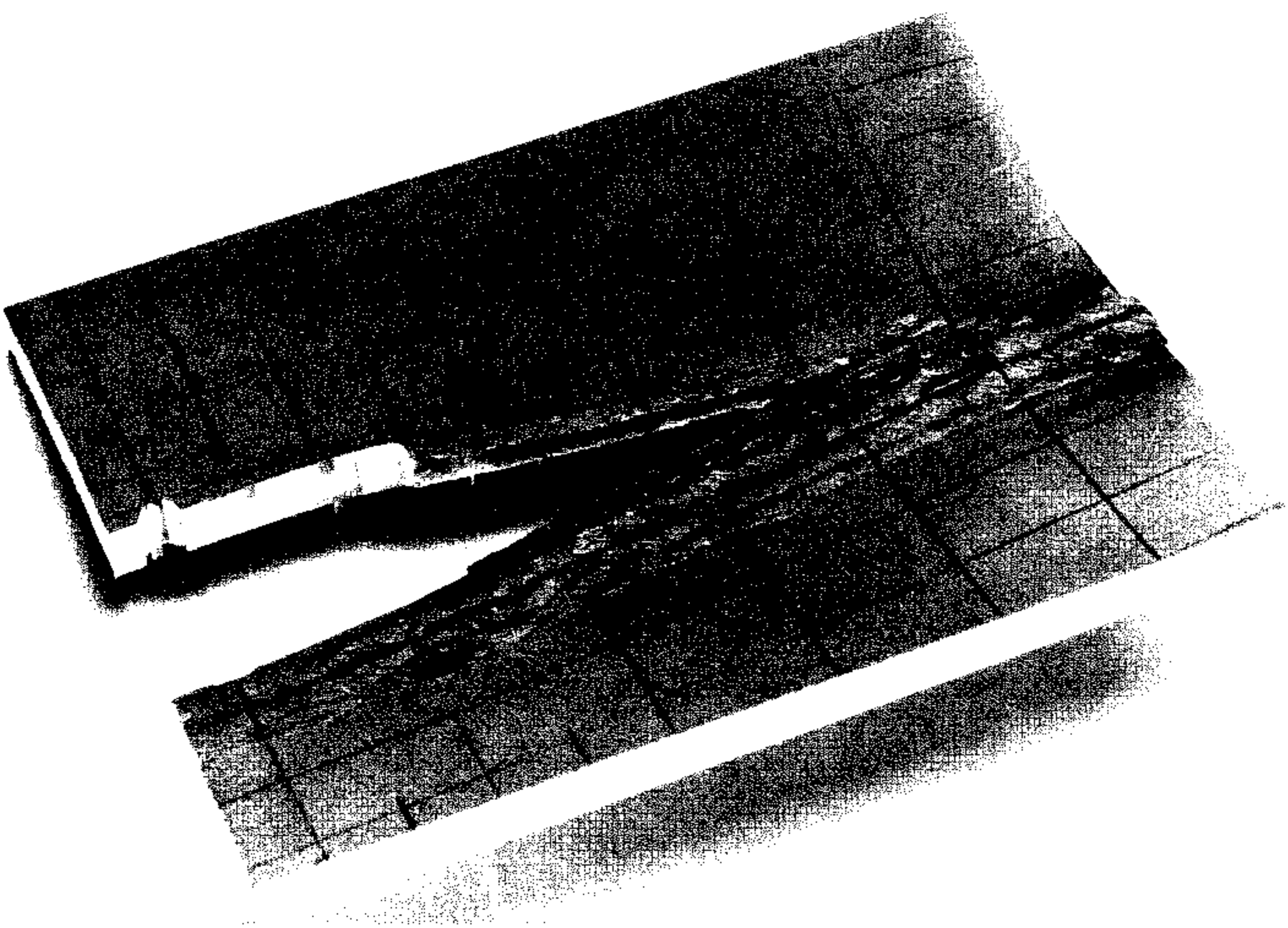
Fracture mechanics, the science of calculating material characteristics, stresses, and flaws in plant equipment to evaluate structural integrity, usually spares the owners of nuclear power plants unnecessary expense. Instead of replacing equipment prematurely or waiting for costly, unscheduled materials failures that can take months to repair and cost thousands of dollars a day for replacement power, utilities use fracture mechanics techniques to carefully consider their options. If analyses show repair is unnecessary, plant operation can confidently be resumed. If repair is required, it can either be done immediately or, if deferrable, be scheduled for a later, more convenient outage.

Hidden costs

But using fracture mechanics doesn't always work that way. "The integrity of a nuclear reactor can only be assessed accurately if one considers the real properties of the construction materials, the actual stresses experienced by the plant during all phases of operation, and the defects within the plant," says Theodore Marston, manager of EPRI's fracture mechanics research in the Nuclear Power Division. Needlessly or prematurely replaced equipment, downtime, and replacement power may result from unduly large inaccuracies in the evaluations of materials characteristics and stress, in nondestructive examination procedures,



Fracture mechanics methods are established by stress tests such as these. A saw cut is made in a specimen, a specific level of stress is applied, and the data from the resultant fracture are cataloged for study. This specimen illustrates the straight saw cut, the jagged split of the ductile fracture, and the rippled weld area adjacent to the fracture. The stubs left by displacement-measuring devices are on the reverse of the sample (top illustration).



or even in the fracture mechanics methods themselves.

Fracture mechanics methods, as well as methods for evaluating materials characteristics and stress and for performing nondestructive examinations, are clearly spelled out in NRC regulations and regulatory guidelines. These guidelines, often based on ASME codes, apply to pressure vessels, pipes, valves, and other plant components subjected to the high pressures and temperatures of the nuclear primary coolant system. These metal components must be routinely monitored for flaws, which can range from infinitesimal material inhomogeneities to nonmetallic material entrapped during the welding processes to fatigue or stress corrosion cracks that may form during operation. The flaws are then evaluated to see if they will significantly affect the plant's integrity and, consequently, its safe and economic operation.

Prescribed guidelines do not always reflect true safety margins. They may, in fact, be overly conservative because of insufficient or inapplicable data, and this extra measure of conservatism may result in limited operation or possibly premature retirement of equipment.

One area of particular interest to utilities is the fracture mechanics analyses of ductile materials. Karl Stahlkopf, director of the Systems and Materials Department in the Nuclear Power Division, explains that the methods the NRC requires to calculate how flaws cause structural failure presently assume that materials act in a brittle manner—in the extreme, like glass.

Although these brittle fracture analyses describe the way some metals behave, they do not characterize the materials used in the construction of nuclear power plants. Structural materials used in the plant's pressure boundary, including piping and pressure vessels, are specifically chosen for their great ductility and toughness. When these materials fail, they behave in a ductile—not a brittle—manner. The material deforms significantly (like taffy being stretched) and the flaw grows slowly and stably until the material finally breaks. The high temperatures under which these components operate further enhance their ductility. This process absorbs large amounts of energy.

Conservative guidelines

When methods that characterize the behavior of brittle materials are applied to ductile materials, the resulting guidelines may prove to be extremely conservative. Although these guidelines are eminently safe for ductile materials, plant equipment made of such materials may have to be operated at reduced power, repaired, or even retired well before its design life is over. New nuclear plants are made with materials of even higher ductility, so the current standards may be even more inappropriate for them.

Until recently, design engineers had no choice but to accept the application of brittle fracture methods and guidelines to ductile materials. Unlike brittle fractures, which behaved simply and were relatively easy to calculate, ductile fractures were complex and required the help of advanced—and expensive—computers to calculate their behavior.

In recent years, however, the cost of premature equipment repair or replacement has been rising steadily. New equipment is increasingly expensive, so it is essential to run equipment for its full service life. The price of the replacement power required during outages now hovers at about $600,000 a day for a 1-GW (e) plant. Furthermore, the skilled personnel who make the repairs in highly irradiated plant areas are in short supply, and their exposure time to radiation is carefully restricted.

The use of ductile fracture mechanics would ease this predicament by providing more realistic guidelines for repair and outage decisions, thus extending the life of flawed vessels and pipes. And Stahlkopf notes that engineers now have the advanced computers and programming methods to develop and evaluate the complex ductile fracture calculations. It would seem that this is a good time to consider applying ductile fracture mechanics procedures to the appropriate plant materials when brittle fracture mechanics analyses indicate excessive safety margins.

Before existing ASME codes and NRC guidelines can be revised to encompass ductile fracture mechanics, ductile methods and supporting data have to be solidly established. Since 1975 EPRI has pursued this information through contracts with General Electric Co.; Battelle, Columbus Laboratories; Lawrence Livermore Laboratory; Science Applications, Inc.; SRI International; and others. Complementary research has been conducted by NRC, as well as other organizations. Data and methodologies from all these efforts are fully shared, compared, and integrated, and with this extensive data base, EPRI has developed a series of simplified ductile fracture calculation methods suitable for use on power plant pressure vessels and piping. (These simplified calculations will appear in a ductile fracture mechanics handbook that EPRI intends to publish this year.) Each calculation can be done by an engineer in only a few hours with a hand calculator. Computer calculations, at a cost of $5000–$10,000 per run, will generally be unnecessary.

Power plant applications

These ductile fracture mechanics techniques have many potential applications within nuclear power plants. One important application is the evaluation of cracks in piping materials.

Until recently, intergranular stress corrosion cracking (IGSCC) had been noticed only in small-diameter piping. Several years ago, however, welds in larger-diameter piping in certain BWRs began to show signs of IGSCC as well. This cracking was of particular concern because of the extended outage time that would be required to repair the pipes if the cracks were found to cause concern about the integrity of the system. Because

To demonstrate safety factors, a series of experiments at Oak Ridge National Laboratory tested pressure vessels to the point of failure. The photo on the left shows a brittle fracture that occurred during an experiment on a cold test pressure vessel. The photo on the right shows a ductile fracture that occurred when a similar experimental pressure vessel was tested when hot. Current operating procedures ensure that nuclear pressure vessels are always operated in a hot, or ductile, condition and are therefore at their optimal strength.

no appropriate ductile fracture mechanics techniques were available to assess the integrity of these highly ductile stainless steel pipes, NRC required that any pipes with evidence of IGSCC were to be repaired immediately.

This solution, while certainly prudent, was not necessarily correct. Research was necessary to establish the ductile fracture techniques that would predict crack behavior so that a more realistic course of action could be taken.

EPRI, with funding from a BWR owners group, undertook this research early in 1979. Subsequent project results show that a slow leak—instead of a large break—would occur and piping configurations in BWRs make unstable fractures extremely unlikely. So in some cases it may be justifiable to defer crack repairs until the next scheduled outage. An ASME task group has been evaluating this and other research and will recommend that ductile fracture mechanics techniques be included in the ASME codes that apply to BWR pipe cracking.

Another possible application of ductile fracture mechanics techniques is the proper assessment of radiation damage. When pressure vessel materials are exposed to the fast neutrons that escape the radioactive core, the fracture resistance of those materials is lowered and the vessel becomes increasingly brittle. If the embrittlement is too great, the integrity of the pressure vessel may be threatened. Accordingly, the NRC specifies certain embrittlement limits.

Should these limits be unmet, an exhaustive series of integrity analyses must be performed if a plant's operating license is to be continued. Among other requirements, these analyses include the collection of irradiated fracture resistance data on relevant steels. But although the pressure vessel is made of ductile steels, NRC-prescribed techniques are brittle fracture techniques and so do not reflect actual fracture resistance. "The vessel materials may be as much as three times more resistant to fractures than indicated by the brittle fracture techniques specified in current regulations," explains Marston. Yet if the analyses fail to show an adequate safety margin, NRC might require thermal annealing to bring the embrittled area back within code limits. This process is costly, time-consuming, and as yet untried.

To avoid unnecessary corrective actions, the most accurate embrittlement predictive methods possible must be used. Extensive research is under way at EPRI, NRC, and elsewhere to develop ductile fracture methodology for use where appropriate. Three programs are attempting to measure the fracture resistance and Charpy properties of irradiated materials, using ductile fracture mechanics: the NRC's heavy-section steel technology research, Babcock & Wilcox Owners Group's studies, and EPRI's projects. Data are still coming in, but by the time the research is completed, the significance of the existing embrittlement limits in terms of fracture resistance will have been estimated, and recommendations for revised embrittlement limits will have been developed.

Radiation embrittlement in pressure vessels and cracks in piping are two of the most important plant integrity areas in which ductile fracture mechanics can be of value. But they are not the only areas: research is going ahead in other parts of the nuclear power plant as well. Nor are nuclear power plants the only structures where ductile fracture mechanics can be applied: any power plant where structural integrity is of concern may also benefit from these techniques. As research moves ahead, an ever-improving understanding of structural integrity emerges. As a result of this deeper understanding, existing codes and guidelines can be revised to more realistic—and still prudent—safety margins. ■

This article was written by Nadine Lihach. Technical background information was provided by Theodore Marston and Karl Stahlkopf, Nuclear Power Division.

ET8: Upbeat on Energy

Despite proposed federal funding cuts for energy programs, an optimistic outlook on technology progress prevailed at the ET8 conference in Washington, D.C.

Energy specialists from the United States and abroad heard progress reports on a wide range of energy topics at the recent eighth annual Energy Technology Conference and Exposition (ET8). Key subjects covered at the three-day conference included the future of electricity and natural gas, synthetic fuels, energy storage, solar, cogeneration, heat recovery, utility rate design, and conservation in buildings.

The mood of the conference, which focused on the 1980s as the new fuels era, was generally upbeat as a number of participants expressed optimism that many new energy technologies would begin to pay off soon. This tone was particularly apparent in many of the exhibits, where a variety of new and improved products and equipment, ranging from efficient light bulbs to fluidized-bed combustion systems, were displayed.

On the minds of many of the participants, however, were the proposed cuts in federal funding for many energy research, development, and demonstration programs. Although some participants indicated that the private sector would be able to carry on much of the work, others warned that continued federal support was still needed in some cases, particularly in the high-cost, high-risk projects.

The conference, sponsored by EPRI, the American Gas Association, the Gas Research Institute, and the National Coal Association, has been billed as the largest of its kind in the world. According to conference officials, the estimated attendance of 7500 was an increase of 30% over last year and the 350 exhibit booths represented a 32% percent increase.

Keynote Stresses Free Market

J. Peter Grace, president and chief executive officer of W. R. Grace & Co., opened the conference March 9 by calling for the elimination of price controls and the reduction of regulation on all energy forms. In his keynote address, Grace suggested that gasoline prices should rise to parity with those of European nations, which are paying as much as $3 a gallon. "The result would be to reduce U.S. consumption, which now runs at nearly half of the total world use, despite having only 5% of the total population," he said.

At a press briefing later, Grace called for a six-point plan on energy and the economy: balancing the budget over the business cycle; cutting the top personal tax rate to 36%; adjusting all personal and corporate profits for inflation before taxing; eliminating capital gains tax; eliminating price controls and reducing energy regulations; and forming an organization of crop-exporting countries to price grain exports toward parity with oil or gold. In response to questions, Grace said he favored ending subsidies for all energy forms, including nuclear power and synthetic fuels, and commented that subsidies have been required because of price controls.

EPRI's president, Floyd L. Culler, told the press briefing, however, that because utilities are regulated, their problems of risk in developing new or improved technologies are different from those of a free market economy. Therefore, government support is sometimes needed for the truly long-term developments.

Culler was supported by comments from another press-briefing participant, George H. Lawrence, president of the American Gas Association. The regulated gas utilities are ready to put up 25% of the funds for new high-cost, high-risk energy

Culler

increasing the availability of electricity by a factor of 2. Otherwise it could face adverse economic consequences, according to Culler.

Another speaker who highlighted the promise of electricity was S. David Freeman, chairman of the board, Tennessee Valley Authority, and a member of EPRI's Board of Directors. "It is vitally important that we actively promote the increased use of electricity in applications where it can substitute for scarce petroleum and where maximum efficiency has already been achieved through strict conservation techniques," Freeman told a luncheon audience. "No other form of energy offers so much opportunity for innovation as a petroleum substitute, whether in transportation, residential heating, or a host of industrial applications. And no other type of energy is available for these purposes in so convenient and environmentally acceptable a form."


Freeman

technologies, but the financial markets are not willing to put up the rest until they see that the technologies work. Thus, the industry must sometimes turn to the government for assistance.

Lawrence called natural gas a bridge to the energy technologies of the future and an essential element in backing out of the nation's foreign oil use. With the right regulatory, legislative, and economic climate, the gas industry will increase supplies by 8–60% by the year 2000. Lawrence also cautioned that sudden total deregulation of natural gas would have severe impacts. "There has to be a slow transition to get rid of 25 years of regulations."

Meanwhile, Culler called electricity the best way for the nation to reduce dependence on foreign oil. Electricity should be in for a period of relatively vigorous growth; however, the industry presently is facing great difficulties in increasing generating capacity. The country will have to get on with the job of

Freeman made a strong pitch for energy conservation as the top priority for reducing the nation's petroleum imports. "Conservation is not only the quickest and easiest way to reduce petroleum imports, it is also by far the cheapest, at least for the first several million barrels," he told the group. "Other important energy sources include wood and passive and active solar heating. However, conservation and other forms of decentralized energy can only go so far in reducing the U.S. appetite for imported oil in the transportation and industrial areas.

"Electricity can provide a reliable fuel for electric cars and mass transit to get people back and forth to work; for electric trains to move people and freight between cities; and to replace oil in power plants, factories, and commercial establishments. Even if synthetic fuels were available today," he continued, "we would be well advised to choose electricity over synthetics as a substitute for oil wherever electricity is feasible."

Homeowners now being encouraged to hook up to gas heat or to switch from electricity to natural gas will soon regret the move as natural and synthetic gas prices rise more steeply than electricity, according to Freeman. "Homeowners may complain now about the cost of heating an electrically heated home, but people heating with gas or oil will be clamoring for electric heat pumps before this decade is over."

Meanwhile, in another important address, a European energy expert, Wolf Häfele, offered some good news, as well as a warning to the conference attendees. Häfele, formerly deputy director of the International Institute for Applied Systems Analysis in Laxenburg, Austria, and now director of Kernforschungsanlage Jülich GmbH in Jülich, Germany, presented the results of a seven-year international study of global energy needs over the next 50 years. The study, conducted by scientists from 20 nations, concluded that the technology and resources would be available to satisfy the greatly increased energy demands if the world population doubles to eight billion. However, to meet the demand, which could reach three to four times today's level, full use of all available energy sources—oil and gas, solar, renewables, and nuclear—will be required, Häfele indicated. Dirtier and more expensive fossil fuels and vast quantities of synthetic fuels will have to be developed, as well as both large-scale solar electric plants and nuclear breeder reactors.

Promising Technologies Highlighted

While experts like Häfele were discussing the big energy picture at the conference, other speakers were focusing on specific down-to-earth technologies and ideas that show promise for extending our existing resources or tapping new ones. A few key papers are reviewed below.

"Gasification–Combined Cycle" David Ahner of General Electric Co. described the 100-MW Cool Water integrated coal gasification–combined-cycle demonstration plant presently scheduled to begin operation in late 1983. The project, cosponsored by EPRI; Southern California Edison Co. (SCE); Texaco, Inc.; Bechtel Corp.; and General Electric, is designed to demonstrate an advanced power generation concept that offers low environmental impact and high efficiency potential. It integrates the Texaco coal gasification process with a modified General Electric combined-cycle power plant. In the system, a coal-water slurry and oxygen would be fed into a gasifier to produce an intermediate-Btu gas. The gas would then be cleaned for use in a turbine combustor. The hot gases from the turbine would superheat steam, which, in turn, would generate power in a conventional steam turbine.

The demonstration plant, which is to be built at SCE's Cool Water site near Daggett, California, represents a significant step forward in bringing this advanced concept in clean electric power from coal to commercial reality.

"Coal Cleaning" The costs of building and operating future coal conversion plants could be reduced by first cleaning the coal of its high ash content before it is used to produce synthetic gases or liquids, reported Dale R. Simbeck of Synthetic Fuels Associates. Coal cleaning has not grown with the increase in U.S. coal production, but the developing synthetic fuels industry may reverse this trend because of the many advantages. The important potential benefits of cleaning coal include reduced variability of coal characteristics, reduced ash, reduced pyritic sulfur, increased heating value, and increased market value.

Simbeck's paper described a 500-t/d coal-cleaning demonstration plant being built at Homer City, Pennsylvania, under the sponsorship of EPRI, the National Coal Association, and several utilities. The results of coal tests at the plant will enable accurate economic analysis of costs of various coal-cleaning equipment, yields, and benefits.

"Nuclear Waste Management" Robert W. Kupp, vice president of The S. M. Stoller Corp., provided an overview of nuclear waste management and focused on what he considered the low risks involved in the disposal of radioactive nuclear wastes. He pointed, for example, to the low environmental risks of nuclear waste disposal versus the possible hazards of other toxic materials, such as copper, mercury, lead, arsenic, and polychlorinated biphenyls (PCBs).

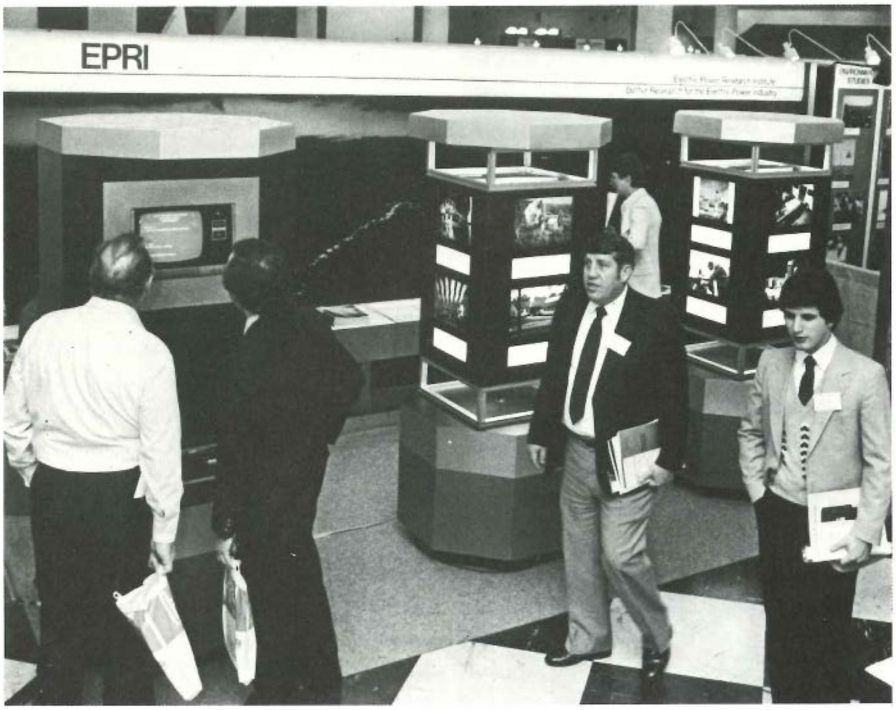
"We do have major technical waste disposal problems in our country, but clearly nuclear waste is not one of them," Kupp said in his paper. "First, nuclear wastes have always been recognized as a hazard that something should be done about; second, the quantities are so small that we can afford to do something about it; and third, by any rational standard, even the most improbable failures of disposal approaches used and being considered would be a nominal societal risk."

"Energy Storage" Mark McDermott of General Electric Co. reported that advanced energy storage batteries can have a major role in reducing future electric utility dependence on premium fuels. Such batteries could store electricity produced at off-peak hours by coal or nuclear energy for use during peak power demand, when utilities often must bring oil- or gas-fired generators on-line.

One advanced battery being developed by General Electric with EPRI support is the beta battery. The electrodes of the beta battery are liquid sodium and sulfur. They are separated by a solid beta-alumina ceramic electrolyte. Although technical challenges remain, utility battery systems capable of producing 20 MW of power for a five-hour period and having a life of at least 10 years are expected to be available and operating after 1985. These batteries could save at least 0.4 quadrillion (10^{15}) Btu of premium fuels per year if they were available today. Projected to the year 2000, they could produce savings of 0.8 quadrillion Btu of oil a year. (U.S. petroleum consumption was 37.3 quadrillion Btu in 1979.)

Two other potentially important storage concepts, compressed-air storage and underground pumped hydro, were discussed by Peter Schaub of Potomac Electric Power Co. Schaub described the results of recent preliminary design studies in a project cosponsored by DOE, EPRI, and Pepco. The studies showed that each concept could provide a net system fuel savings of one million barrels of oil a year with fewer environmental impacts than alternative systems. The cost and construction schedules of both concepts are comparable to those of steam electric power plants.

EPRI's exhibit booth at the eighth annual Energy Technology Conference and Exposition (ET8) in Washington, D.C. According to conference officials, the estimated attendance of 7500 was an increase of 30% over last year.



In a compressed-air storage system, air is compressed by a motor-compressor, then cooled and stored in underground rock caverns during off-peak hours. The compressed air is later mixed with fuel and expanded through a turbine generator. Compression normally makes up 60% of a turbine's work. But with this system, there is no need for the turbine to drive the compressor. Thus the turbine can deliver two to three times the electrical output for the same amount of fuel.

The pumped-storage system would use two reservoirs. During peak periods of electricity use, water would flow from an upper reservoir on the surface to an underground reservoir, turning a turbine to produce electricity. During off-peak hours, water would be pumped back to the surface reservoir.

"Photovoltaics" Solar photovoltaic systems, which convert solar energy into electricity, show promise for widespread application in buildings as well as utility central power stations, according to a paper by D. R. Roberts of Westinghouse Electric Corp. Roberts described work that Westinghouse has been doing on flat plate photovoltaic modules with single-crystal silicon cells produced by a patented dendritic web process. Westinghouse is presently forecasting a price below 70¢ per peak watt by 1986, with overall module efficiencies in the range of 16%. The firm has installed a small pre-pilot production line with the idea of transferring the technology from the research and development stage to production of modules for limited demonstration.

"District Heating" William Hanselman of Resource Development Associates described the advantages of district heating as central energy supply systems for urban areas. District heating systems consist primarily of piping networks that transfer thermal energy in the form of steam or hot water from power plants, factories, or other sources to buildings or industries for heating, cooling, domestic hot water, or process steam.

District heating systems were first developed more than 100 years ago, but declined after the introduction of less expensive oil and natural gas. Not only has the technology improved significantly in recent years, but the recent decontrol of oil and the coming deregulation of natural gas may remove the price disadvantage that precipitated the decline of the oil district heating systems. Another advantage of district heating systems is that they could be coupled with such alternative energy technologies as geothermal, solar, and resource recovery systems.

"Cogeneration" A similar concept that could find widespread use in large urban residential and commercial buildings is on-site cogeneration, according to a paper presented by Richard Stone, president of the National Urban Energy Cooperative Funding Corp. Cogeneration, the simultaneous production of electric power and thermal energy, could achieve a system efficiency exceeding 90%, compared with 30% for utility-produced power.

Stone described the Big Six Towers in New York City as an example of a typical on-site cogeneration installation. The 4000-resident complex switched to an on-site cogeneration system a year ago at an initial investment of $2 million in equipment. The cogeneration system, which has a capacity of 4000 kW, is expected to save an estimated $300,000 a year, with heat recovery included. Such facilities should be encouraged not only because of their conservation value but also because they introduce the possibility of competition into an industry that was once considered a natural monopoly and has grown costly and inefficient as a result.

"Utility Rate Design" Robert Malko, chief economist for the Wisconsin Public Service Commission, summarized a rate design study commissioned by the National Association of Regulatory Utility Commissioners. The effort, which involved EPRI, Edison Electric Institute, American Public Power Association, and National Rural Electric Cooperative Association, considered ways to control peak demand and to shift loads from peak to off-peak periods. The focus was on time-of-use rates and direct load controls.

Some of the study's conclusions listed by Malko: time-of-use rates are feasible; meters and other necessary equipment are available to implement time-of-use rates; a thorough customer education program is needed if time-of-use rates are to succeed; peak use can be shifted in specific cases, but the magnitude of the shifts is still uncertain; it is important to collect load and usage data before and during a load management program.

One important aspect of the study was that regulatory commissions, as well as public and private power companies, cooperated to address the issue of load management. It would be worthwhile if similar ventures of interest to the utility industry were carried out in the same fashion.

Load management was also the subject of a paper by Donald H. Denton, Jr., vice president of marketing for Duke Power Co. Denton described a program undertaken by his firm to substantially reduce the summer and winter peak power loads. The program is expected to reduce capital requirements for new construction by more than $10 billion over the next 10 years. This will benefit both the stockholders and the ratepayers.

"Energy Conservation in Buildings" Maxine Savitz, DOE's deputy assistant secretary for conservation, emphasized the importance of energy conservation in reducing the nation's vulnerability to oil disruption, in easing pressures on conventional supplies, and in making the transition to new domestic sources. Conservation should connote energy efficiency and energy productivity, rather than sacrifice and curtailment.

Among the main barriers discouraging capital investment in energy-efficient products and measures in the building sector have been artificially low energy prices and the lack of sufficient information on the part of consumers. Pricing patterns are beginning to change and federal programs aimed at getting information to consumers are under way. Despite information programs and tax and market incentives, however, retrofitting homes with energy-efficient measures has not been occurring at the expected rate, and several barriers still inhibit large segments of the residential market from taking action. These barriers include lack of technical knowledge to sort through the barrage of conservation product claims, a fear of being cheated, and a lack of convenient and advantageous mechanisms for financing and installation of retrofits.

Responding to questions following her address, Savitz said that federal efforts aimed at near-term development of more efficient technologies for buildings will be deemphasized under the president's proposed 1982 budget. Instead, DOE's conservation program will focus on more generic research and development. Federal commercialization efforts will be greatly reduced, with higher prices and tax incentives becoming the main weapons used to help get new products to the market. "Most of the near-term efforts that the federal government has sponsored in the conservation area will be passed to the private sector," Savitz said. "We hope that the private sector will pick them up." ■

This report was prepared by William McCann, freelance writer, and Christine Lawrence, Washington Office.

Spring Elections

At a recent meeting in Washington, D.C., a new chairman, vice chairman, and four directors were elected to EPRI's Board of Directors.

William R. Gould, chairman of the board and chief executive officer of Southern California Edison Co. (SCE), was elected chairman of EPRI's Board of Directors at its meeting in Washington, D.C., on April 14, 1981. Gould succeeds Floyd W. Lewis, chairman and president of Middle South Utilities, Inc., who has served as EPRI chairman since May 1979.

Gould has been a member of the EPRI Board for five years. He has been with SCE since 1948, when he joined the utility as a mechanical engineer. He rose through management to become vice president in 1963, executive vice president in 1973, president in 1978, and chairman and chief executive officer in 1980. He has been a director of SCE since 1971.

In addition to his work at Edison, Gould serves on the boards of several other corporations, as well as being affiliated with professional, academic, trade, and philanthropic organizations.

Charles F. Jack, vice president for engineering and power supply at Buckeye Power, Inc., of Columbus, Ohio, was named Board vice chairman at the meeting. Jack joined Buckeye as chief engineer in 1969 and was appointed to his current position last year. Before joining Buckeye, Jack was chief of the Division of Power Marketing at Southwestern Power Administration in Tulsa, Oklahoma.

Gould

Four new directors were elected to EPRI's Board at the annual meeting of members on April 13, 1981, in Washington, D.C.: Frank W. Griffith, chairman of the board and president, Iowa Public Service Co.; Don D. Jordan, president and chief executive officer, Houston Lighting & Power Co.; Peter J. McTague, chairman of the board and president, Green Mountain Power Corp.; and George H. Usry, III, general manager, Athens Utility Board, Athens, Tennessee.

Griffith, McTague, and Usry will serve four-year terms, and Jordan will serve for three years. ■

Workshop on the Electric Role

EPRI, American Public Power Association, Edison Electric Institute, National Coal Association, and National Rural Electric Cooperative Association are cooperating with the Atomic Industrial Forum in sponsoring a workshop on how an increased use of electricity can reduce the nation's dependency on imported oil. This Workshop on the Electric Imperative will be held June 14–17, 1981, at the Hyatt Del Monte in Monterey, California.

The purpose of the workshop is to explore the need to use more coal and nuclear energy through electricity to meet the future energy requirements of a viable economy. Sam Schurr, deputy director of EPRI's Energy Study Center, will open the workshop with "The Role of Electricity." His presentation will be followed by three speakers who will examine "Projecting the Demand for Electricity."

During the next four half-day sessions, experts will address "Supplying the Demand for Electricity," "New Uses for Electricity," "Surmounting Financial Constraints," and "Convincing the Public."

Further information on the workshop, including an advance program, a registration form, and a hotel reservation card, is available from AIF's Conference Office, 7101 Wisconsin Avenue, Washington, D.C. 20014.

Electric Field Research Continues

EPRI is currently formulating plans for expanded research into the potential health effects of prolonged exposure to electric fields, including replication of the miniature swine experiment being conducted by Battelle, Pacific Northwest Laboratories for EPRI.

Over the past several years, EPRI and DOE have sponsored a series of parallel experiments at Battelle, Pacific Northwest Laboratories to explore the possible effects of prolonged exposure of mammals to electric fields. DOE's experiment used small animals.

EPRI's experiment, which was begun in mid-1978, used miniature swine as the test subjects. In these tests, sows were exposed to electric fields 20 hours a day, seven days a week, over a period of many months.

The electric fields used in this test were designed to be equivalent to the maximum exposure a human would receive from standing directly under the highest voltage transmission lines that exist in the United States (765 kV). At the present time, 765-kV lines represent 0.5% of the 270,000 miles of transmission lines in the country.

The first results of the swine experiment, which was conducted in specially constructed Battelle facilities near Richland, Washington, were reported by Dr. Richard Phillips, principal investigator, at a February 1981 meeting of the IEEE Power Engineering Society in Atlanta, Georgia. Data on observed biological and behavioral differences between the animals exposed to the electric field and those in a control group, which was in identical conditions, but not exposed, were discussed at this meeting. These differences were seen in the areas of prenatal development and breeding behavior.

However, determining whether the electric field was the cause of the differences is difficult because of several factors, including the outbreak of a dysentery like disease, the treatment, and normal statistical variations.

In an experiment conducted for EPRI by Battelle, Pacific Northwest Laboratories, Hanford miniature swine were exposed to high-voltage electromagnetic fields to determine possible health effects.

Because of the uncertainties introduced by these factors, the experiment has been reviewed by a specially convened panel of experts. This panel, composed of specialists in swine biology and low-frequency field effects, recently concluded that the causes of the results were questionable and recommended that the miniature swine experiment be repeated.

At the Atlanta meeting, Dr. Phillips of Battelle presented the data collected in this experiment. They showed differences in infant mortality, prenatal mortality, mating performance, development behavior, and incidence of fetal malformation. In some cases, the incidence of the factors listed above were higher in the control group; in other cases, they were lower. Specifically, in the first group of litters conceived after four months of continuous maternal exposure, prenatal and infant mortality were lower among the swine exposed to the field. These litters also showed no increase in congenital malformations.

When this original group of sows was bred for the second time, which took place 18 months after the continuous exposure was started (and following the outbreak of dysentery), a higher incidence of fetal malformations was seen in the exposed group.

When the time came to breed the first generation of swine born in the exposure facility, the animals resisted mating.

Scientists are not certain what effect, if any, the outbreak of dysentery or its treatment may have had on the problems observed later. (The outbreak began among the exposed animals, and the treatment with antibiotics was begun before the epidemic had affected the control group to the same degree.)

Therefore, the only satisfactory procedure appears to be continuing analysis and follow-up research, including redoing this miniature swine experiment. This course results from the evaluations made by EPRI, Battelle, and the panel of experts. Thus, the information yielded by three years' investigations will be used to design follow-on experiments under continuing EPRI sponsorship. ■

NSAC Director Zebroski Elected to National Academy of Engineering

Edwin L. Zebroski, director of the Nuclear Safety Analysis Center (NSAC), has been elected to the National Academy of Engineering. Zebroski and 62 other new members will be installed in November at the seventeenth annual meeting of the academy in Washington, D.C.

Election to the academy is one of the highest professional distinctions honoring those who have made important contributions to engineering theory or practice or who have demonstrated unusual accomplishments in pioneering new fields of technology. Zebroski was elected by vote of the present members "from a very large list of nominees eminently qualified for membership," Cortland D. Perkins, president of the academy, wrote Zebroski. "Your election signifies recognition by your peers of your outstanding contributions to the broad fields of engineering, engineering science, and technology."

Director of NSAC since its founding in April 1979, Zebroski was previously director of the Systems and Materials Department, Nuclear Power Division. Involved in the nuclear energy field since the World War II days of the Manhattan Project, Zebroski came to EPRI after a 27-year career with General Electric Co., where he made many contributions to the technology.

In the Manhattan Project, Zebroski was involved in the electromagnetic separation of uranium and in the process for extraction and purification of the first kilogram-scale production of uranium-235. He joined General Electric in 1947 at its research laboratory, then moved to the Knolls Atomic Power Laboratory as manager of separations technology and organized the pilot plant operation that developed and demonstrated the Redox and Purex nuclear fuel recovery processes. He holds a patent on an extraction device that is used worldwide for these processes. For this work he received the Charles A. Coffin Award.

Later, Zebroski worked on advanced reactor design and was project engineer for the reactors that powered the submarine *Triton*, then the world's largest. He was coauthor of an initial design study at General Electric of a direct-cycle boiling water reactor, which paved the way to today's BWR commercial power plants in use around the world.

From 1954 to 1957, Zebroski was manager of nuclear engineering at Stanford Research Institute. In 1957 he returned to General Electric at its nuclear division in San Jose, California, working on the design of advanced reactors. He was involved in the design, development, and introduction of large-scale power reactors, including pioneer units in the Chicago area, California, Michigan, India, and Italy. He later managed breeder reactor development at General Electric.

Zebroski is a native of Chicago. He earned a BS in physics and chemistry at the University of Chicago and a PhD in physical chemistry at the University of California at Berkeley. He has written or been coauthor of about 140 technical publications, is a member and fellow of several professional societies, and is on the Board of Directors of the American Nuclear Society. ■

CALENDAR

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

JUNE

16–18
Technology Seminar II: Communications Systems for Distribution Automation and Load Management
Denver, Colorado
Contact: A. Johnson (415) 855-2833

17–18
Seminar: Steam Turbine Rotor Reliability
Charlotte, North Carolina
Contact: Georgine Jacobs (415) 855-2252

19
Demonstration: American Electric Power Turbine Maintenance Facility
Charleston, West Virginia
Contact: Georgine Jacobs (415) 855-2252

23–25
Workshop: Modeling for Stability Calculations
(Attendance limited.)
St. Louis, Missouri
Contact: A. Johnson (415) 855-2833

23–25
Seminar: National Fuel Cell
Norfolk, Virginia
Contact: E. A. Gillis (415) 855-2542

JULY

15–17
Workshop: Fabric Filter
Denver, Colorado
Contact: R. C. Carr (415) 855-2422

AUGUST

26–27
Workshop: Fossil Plant Heat Rate Improvement
St. Paul, Minnesota
Contact: E. A. DeMeo (415) 855-2159

R&D Status Report
COAL COMBUSTION SYSTEMS DIVISION

Kurt Yeager, Director

SOLID BY-PRODUCTS AND HAZARDOUS WASTE DISPOSAL

This is the third status report on the activities of the solid by-products and hazardous waste disposal subprogram. A number of project reports have been issued since last year's summary, and these are described below. The previous Journal *reports (June 1979, p. 38, and May 1980, p. 43) discussed the uncertainty facing utility designers because different performance standards for hazardous, nonhazardous, and special wastes were being prepared by EPA but had not yet been finalized. In May 1980 EPA regulations eliminated the special-waste category; uncertainty still exists regarding hazardous and solid wastes, however, because final regulations have not been promulgated in complete form. The October 1980 amendments to the Resource Conservation and Recovery Act (RCRA) exempt coal combustion wastes from the hazardous-waste provisions for three years, pending the results of an EPA study.*

PCB disposal

As most polychlorinated biphenyls (PCBs) in this country are utility-owned, compliance with federal regulations on their storage, handling, and disposal is a matter of concern to the electric utility industry. PCB research is being performed by the Coal Combustion Systems, Electrical Systems, and Energy Analysis and Environment divisions; thus interdivisional coordination and planning are necessary.

To assist utilities, a four-volume report (FP-1207) was published. Volume 1 discusses the distribution of PCBs in electrical equipment around the country and summarizes disposal options. Volumes 2 and 3 provide guidelines for preparing federally required spill prevention control and countermeasure plans. Volume 4 summarizes the October 1979 test incineration of PCB capacitors and PCB liquids at a facility owned and operated by Energy Systems Co. in El Dorado, Arkansas. As a result of this test, the facility has become one of two commercial incinerators in the country certified to burn PCBs, and the only one approved to incinerate PCB-contaminated solids (e.g., PCB capacitors).

Future work will be concerned with methods of cleaning up spills and disposing of or destroying PCBs and PCB equipment. A project is pending, for example, to assess the feasibility of a process for accelerating photodecomposition of PCBs. This process, involving photosensitization by using a chemical substance, is being considered for in situ destruction of PCBs in transformer or capacitor oil at a spill site.

Instrumentation to measure PCBs during spill cleanup—specifically, a photoionization detector to measure PCB levels in soil—is the subject of a recently initiated project with Oak Ridge National Laboratory (RP1263-5). The objective is to develop a portable field instrument that would allow a utility to make on-site decisions about the adequacy of its PCB cleanup efforts and eliminate delays caused by the need for laboratory analysis. The device is based on ionization of organic molecules with ultraviolet light. A low-energy ultraviolet lamp should ionize PCB vapors but not other organics present.

Artificial reefs for coal wastes

Because coal will be the major energy resource in the United States during the next decade for replacing oil-fired capacity and for new generation, large quantities of coal ash will be produced. Also, the use of flue gas desulfurization (FGD) scrubbers to remove sulfur oxides from coal combustion gases will produce large quantities of scrubber sludge. In urban regions, land for the disposal of these coal wastes will be extremely difficult to find. Thus EPRI (together with EPA, DOE, the New York State Energy Research & Development Authority, and the Power Authority of the State of New York) is funding a project to assess the feasibility of disposing of the wastes in artificial ocean reefs (RP1341).

In project work during 1980, some 15,000 coal waste blocks were manufactured and placed in an ocean reef off Long Island, New York. The blocks were made with machinery from a commercial concrete block construction plant (Figures 1 and 2). They were subjected to steam-curing, which in one day produces a greater compressive strength than other curing methods produce in one month. Fly ash and scrubber sludge mixtures from two different sources were used to provide a range of waste properties. During the next three years, research scientists at the State University of New York at Stony Brook will study the blocks' durability and their effects on the marine ecosystem.

A Phase 1 report describing the experimental work on block composition, size, and manufacture was published in March 1980 (FP-1252). A comprehensive three-volume report on activities up through the building of the reef in September 1980 is being prepared. The third of these volumes will include an engineering-economic evaluation of this disposal option prepared by Michael Baker Jr., Inc., under RP1728. The study showed that the cost of block production and reef construction ranges from $19 to $25 per dry ton, depending on the cost of capital.

Sludge and ash disposal manuals

An early product of EPRI's solid-waste research was the *Flue Gas Desulfurization*

Figure 1 Conventional concrete block machine used to make coal waste blocks for the artificial ocean reef. The machine can produce 900 of the 8 × 8 × 16-in blocks per hour.

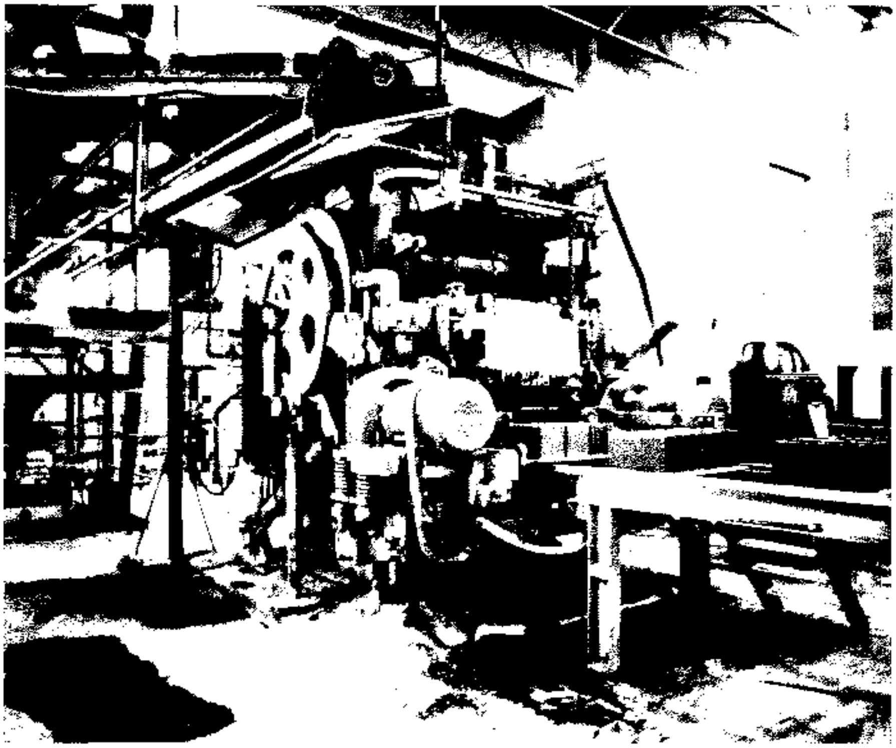


Figure 2 Wall of coal-waste blocks awaiting shipment. Some 15,000 of these blocks were transported offshore for building the reef.

Sludge Disposal Manual (FP-977), developed under RP786-1 and issued in January 1979. A completely revised edition of the manual (CS-1515) was published in September 1980. New and revised information reflects the final requirements of the New Source Performance Standards, the impact of RCRA, the evolution of sludge disposal practices, the growing interest in forced oxidation, and the interest of utilities in the practices and experiences of others. In March 1981 Michael Baker Jr., Inc., began work on a third edition, to be published in 1982. This edition will be entitled *FGD By-Product Disposal Manual* because in addition to sludges, it will cover dry scrubber wastes.

The *Coal Ash Disposal Manual* (FP-1257) was developed under RP1404-1 and published in early 1980. It provides detailed information on the technical and economic factors that govern the selection of preferred disposal systems and locations. Under RP1685-3 GAI Consultants, Inc., has nearly completed a revised edition of the manual, incorporating utility user comments. Publication is scheduled for summer 1981.

The sludge and ash disposal manuals both emphasize the construction of new facilities and have only limited usefulness for retrofitting existing waste disposal sites. A design manual to assist utilities in upgrading existing disposal facilities is being prepared by SCS Engineers, Inc. (RP1685-2). Scheduled for publication this summer, the manual will assess current disposal systems in terms of EPA criteria, describe measures necessary to bring them up to those standards, and present procedures and cost estimates for retrofitting an existing facility. It will cover site closure procedures, the conversion of wet disposal systems to dry systems, alternative retrofit procedures, liner design, the installation of liners and leachate-control systems, the recovery of by-products for reuse, and cost analysis techniques. An engineering evaluation of alternative retrofit systems will be presented, along with selected case studies.

Sludge disposal demonstration

A demonstration of the disposal of sludge from a 20-MW (e) limestone, dual-alkali scrubber at Gulf Power Co.'s Scholz plant (RP1405) is being conducted in conjunction with an EPA process evaluation demonstration. The goal of the project (described in detail in the *Journal*, May 1980, p. 44) is to identify and solve the potential engineering, operational, and environmental problems associated with the disposal of high-sodium, high-sulfite sludges. The 20-MW (e) size of the experimental facility is sufficient for scale-up to commercial size.

The project, which began in April 1979, was intended to run 31 months; however, schedule slippages will extend it through 1982. Because EPA funding limitations have shortened the process demonstration, only one of the three landfill cells can be filled with waste materials during the test. In the later months of the project, the chemical and physical fate of these wastes will be evaluated. The limited field data will be supplemented with laboratory data on selected sludge-ash mixtures.

Monitoring and modeling

Groundwater monitoring and model development are the tasks of an ongoing three-year project at Columbus and Southern Ohio Electric Co.'s Conesville station (RP1406). A monitoring study is being conducted to determine whether full-scale application of the IU Conversion Systems, Inc., fixation-disposal operation reflects laboratory and test-pond results, provides an environmentally acceptable method, and creates any operating problems for the utility. A report on the first phase of monitoring (FP-1172), prepared by Michael Baker Jr., Inc., under RP1406-2, was published in December 1979. During 1980, 17 additional wells were installed. A report on the second year of monitoring is being prepared.

Under RP1406-1 Battelle, Pacific Northwest Laboratories has developed a model for predicting the quality and quantity of leachate and its migration path in the disposal area at the Conesville station. In Phase 1, data were compiled and laboratory studies were conducted to determine saturated and partially saturated permeabilities of sludge and ash materials and to describe the composition and distribution of the sludge-ash leachate. The data base and laboratory results were used to develop, calibrate, and verify a two-dimensional, finite-difference hydrologic flow model for the study area. A Phase 1 report was published in March 1980 (CS-1355), and a user's manual for the saturated flow model will be published shortly. Further model development and verification efforts are under way in Phase 2; during 1981 it is planned to develop a model that will predict leachate migration in unsaturated soils.

Waste containment

The use of liner materials for waste containment and leachate control is comparatively new, and field experience on liner performance is limited. In a project described in the May 1980 issue of the *Journal,* 14 liner materials (six soil liners and eight membrane liners) are being evaluated to determine the effects of exposure to nine types of utility wastes.

During the first year of the tests, membrane liner materials were immersed in samples of liquid wastes, such as metal cleaning wastes. One of the best early indications of waste-liner incompatibility is a change in liner weight or dimensions. Generally, if a liner is incompatible with a waste, it will absorb the waste and swell. However, if the liner contains high levels of an extractable plasticizer, the plasticizer may leach, causing shrinkage and hardening.

During 1980, 20 liner materials were immersed for 120 days in air preheater cleaning wastes. The specimens were then cut in half and their properties measured. The chlorinated polyethylene and chlorosulfonated polyethylene membranes showed only modest swelling, and those made of high-density polyethylene showed almost none. The effects on physical properties were a general downward trend in tensile strength, modulus of elasticity, elongation, and hardness.

Regulatory impact assessment

In 1980 EPRI funded an engineering evaluation of disposal alternatives under different regulatory assumptions; the evaluation was based on case studies at representative sites (RP1728). The objectives were to develop well-documented cost data for the EPRI disposal manuals (RP1685) and to formulate a rational basis for evaluating alternative regulatory proposals and their impacts. A two-volume report on this work will be published in mid-1981. One of the conclusions is that the cost impact of the federal nonhazardous waste disposal regulations will apparently be higher than anticipated.

By-product utilization

In a two-year project completed in September 1980, Oak Ridge National Laboratory studied methods of extracting the trace metals in fly ash (RP1404-2). Many of the recovered metals have a significant commodity value. The project report identifies the two most promising removal processes and presents process flow sheets, preliminary designs for a demonstration plant, cost estimates, and expected benefits from the recovered resources. The processes produce various soluble materials from fly ash (in addition to alumina), some of them in substantial quantities.

Both processes remove all metals that could be released to the environment after fly ash disposal; moreover, a major portion of the leached metals can be recovered in salable form. An engineering-economic analysis of the most promising process studied—direct acid leaching—estimates an annual net return on capital of approximately 30% for a facility that processes a million tons of ash per year. Because the recovered metals will replace imported metals and ores, important balance-of-trade benefits will also result. *Subprogram Manager: Dean Golden*

SO_2 CONTROL BY DRY SORBENT INJECTION

Utilities face the task of removing both fly ash and sulfur dioxide (SO_2) from the flue gas of coal-fired boilers in order to meet clean air regulations. The result is often a complex train of control equipment that requires a large capital investment. Therefore, combining SO_2 and fly ash removal processes is of considerable interest both economically and operationally. EPRI's Air Quality Control Program is conducting full-scale testing on an integrated process that removes SO_2 by injecting a dry sorbent into the flue gas ahead of a baghouse. Fly ash and the SO_2 by-product are then collected in the baghouse. Compounds of interest for use as dry sorbents are nahcolite (naturally occurring sodium bicarbonate, $NaHCO_3$) and trona (a naturally occurring mixture of sodium bicarbonate and sodium carbonate).

Full-scale demonstration

The primary advantages of dry sorbent injection are the lower capital costs ($50/kW less than wet scrubbers or spray dryers) associated with removing particulate matter and SO_2 in a single system and the greater availability and reduced maintenance resulting from simplicity of design. Also, energy and water requirements are lower than for a wet scrubbing system. Disadvantages include uncertainties about the availability and cost of dry sorbents and the disposal of the solid by-product, which contains significant amounts of sodium.

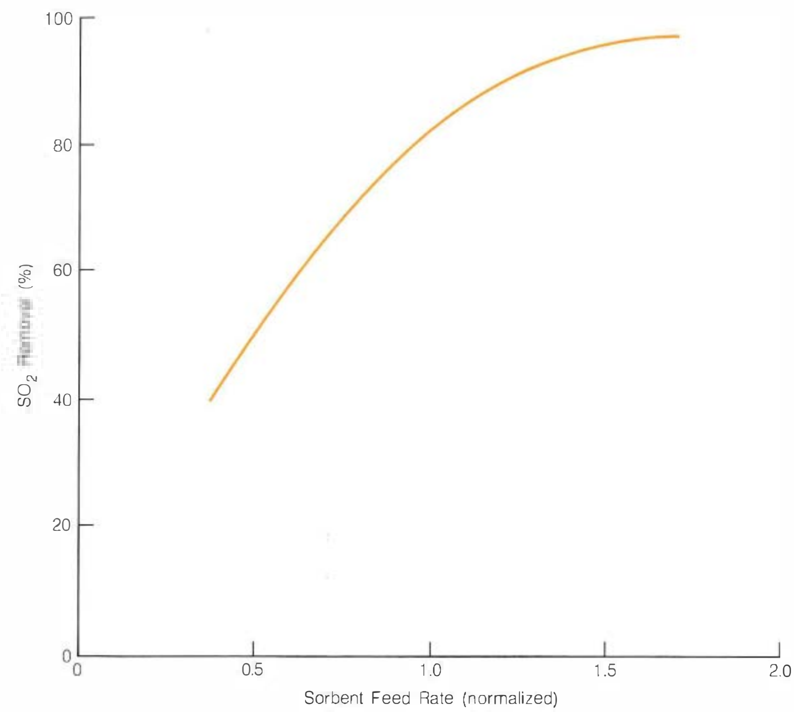
To quantitatively evaluate and optimize the dry sorbent injection process, EPRI, Public Service Co. of Colorado, and Multi-Mineral Corp. (a wholly owned subsidiary of the Charter Co.) are sponsoring a full-scale demonstration of the process (RP1682). This demonstration is being conducted at

Unit 1 (22 MW) of the coal-fired Cameo station near Grand Junction, Colorado. In the first phase of the project, pulverized nahcolite was used. The objectives of this phase were to determine the amount of nahcolite required to achieve an SO_2 removal level of 70% and to observe the short-term effects of the dry sorbent injection process on baghouse operation and performance. The process for the Cameo facility was designed by Stearns-Roger Engineering Corp.

The SO_2 removal efficiency of the dry injection system was evaluated as a function of the nahcolite feed rate and the baghouse operating parameters. Results support the findings of a previous laboratory study under RP982-8 (*EPRI Journal,* June 1980, p. 52). SO_2 removal was slightly more efficient in the demonstration than in the laboratory because the nahcolite injected at Cameo had been pulverized to a significantly finer particle size (70% of the particles smaller than 400 mesh). Finer particles have a greater reactive surface area, which (as documented in the laboratory tests) promotes greater SO_2 absorption.

In the Cameo tests, the finely pulverized nahcolite was injected upstream of the baghouse into flue gas whose temperature was 290°F (143°C). When stoichiometric amounts of the sorbent were used, an SO_2 removal level of 80% was achieved; a 70% removal level was achieved when approximately 0.75 of the stoichiometric amount was injected (Figure 3). It was found that the nahcolite was not distributed equally among the baghouse compartments, which resulted in different SO_2 removal levels in the compartments. Ways to improve particle and flow distribution are under study.

Figure 3 The relationship between SO_2 removal and the amount of nahcolite used was measured at the Cameo demonstration facility. The sorbent feed rate is the actual nahcolite feed rate normalized to the stoichiometric feed rate. Changes in nahcolite particle size and in the temperature at the injection location may influence this relationship. Further tests are scheduled to optimize the use of nahcolite for dry injection.



The impact of the dry injection process on the overall operation of the baghouse was minimal. Removal of the fly ash–reacted nahcolite cake from the fabric is not significantly more difficult than the normal operation of collecting fly ash only. These findings suggest that the injection process does not impose a significant pressure drop penalty, but they will have to be confirmed in long-term continuous operation.

Future research

The demonstration results to date indicate that using the dry injection process has technical and economic merit. However, more data are needed to optimize nahcolite injection procedures. In Phase 2 of the demonstration, scheduled to begin this summer, further tests will investigate the effects of injection temperature and nahcolite particle size on overall SO_2 removal efficiency. Also, Public Service Co. of Colorado is planning engineering changes to distribute the flow of gas and particles more evenly among the eight baghouse compartments.

Previous studies have clearly indicated that nahcolite is the most reactive sodium-based sorbent for use in the dry injection process. In view of the nahcolite demand that could be created should the process be applied broadly in the utility industry, a key question is whether adequate supplies of nahcolite will be available commercially. Multi-Mineral has already unveiled plans to open a 1,000,000-t/yr nahcolite production facility. Other sodium-based sorbents will be tested in short (one- or two-day) single-parameter tests at Cameo to enable direct comparison with nahcolite.

In conjunction with the Cameo demonstration, EPRI is conducting an extensive evaluation of the chemical and physical properties of the by-product for disposal. Also, an economic study is planned that will use the data from the demonstration to develop information to help utilities evaluate the dry injection process in terms of their specific needs. *Project Manager: Richard Hooper*

R&D Status Report
ELECTRICAL SYSTEMS DIVISION

John J. Dougherty, Director

TRANSMISSION SUBSTATIONS

Radio frequency interference from HVDC converter stations

HVDC converter stations inherently generate electromagnetic noise that can interfere with radio, television, and other communication systems. Such interference can be particularly troublesome in urban areas. Generally, the interference levels around converter stations are controlled by two techniques: metallic shields are built into the walls, ceilings, and floors of the valve halls inside the stations; and radio interference filters are used on the transmission lines connected to the converter station. These techniques are obviously very costly. For example, the entire yard of the Sylmar converter station in Los Angeles had to be enclosed in a screened cage to reduce the interference to a level that would avoid problems in the vicinity of the station.

Converter stations will continue to be built close to urban areas, and electromagnetic interference from converter stations will continue to be a concern to utilities. It is therefore highly desirable to find improved and less expensive methods of minimizing such interference. EPRI has initiated a project with the International Engineering Co. to investigate radio frequency interference (RFI) and television interference (TVI) around converter stations and to develop methods to minimize RFI and TVI around converter station buildings of existing and future designs (RP1769). The project involves three main tasks.

In the first task, W. R. Vincent, Consultant, will measure electrical noise and power harmonics around four converter stations: the Sylmar station of the Pacific Intertie system, the Duluth station on the Square Butte Electric Cooperative system, the Dickinson station of the CU project (sponsored by the Cooperative Power Association and the United Power Association), and the Astoria station of the EPRI prototype dc link. Both the electric and magnetic noise fields of vertical and horizontal polarizations will be measured inside as well as outside these facilities. The spectral, temporal, and amplitudinal characteristics will be measured over a frequency range of 100 Hz to 1 GHz.

In the second task, Ohio State University will fabricate a 1/100-scale model of the Dickinson station to determine if modeling can be used to simulate the properties of radiation emitted from a substation. Ohio State will also make electric and magnetic field profile measurements at the Dickinson station as a guide in designing the converter station model.

In the third task, International Engineering will define and evaluate techniques for mitigating RFI from converter stations. These mitigation techniques will be based on results and insights from the measurement and modeling tasks. It is expected that this project will be completed in the fall of 1982. *Project Manager: William Blair*

DISTRIBUTION

Corrosion of concentric neutrals

Over the past 20–25 years, solid-dielectric concentric-neutral cable has been increasingly used by electric utilities. As a result, more than 200,000 mi (300,000 km) of concentric-neutral cable is presently installed and in service throughout the United States. Although a large portion of this cable is directly buried in the ground, another significant portion is installed in underground conduits. A cable-in-duct system calls for a higher initial investment, but it provides a utility with a greater degree of flexibility for future system growth, cable repair, and cable replacement, usually resulting in an overall lower cost when compared with the direct-buried system.

Because of these advantages some electric utility companies that in the past used only the direct-buried system have now started to place cables in duct. However, on removing concentric-neutral underground residential distribution (URD) cable from ducts, some utilities have noted that the neutral wires show evidence of severe corrosion. System reliability, fault detection, interrupting devices, and safe operating practices depend on the integrity of a continuous metallic neutral, so any significant damage to these neutral wires is of major concern.

In an effort to alleviate a similar corrosion problem of concentric-neutral conductors on direct-buried cables, EPRI has funded several projects that address both the cause and the methods of mitigating this corrosion. Concentric-neutral cables installed in conduit, however, may require completely different corrosion prevention criteria than those for direct-buried systems. Some of the mechanisms contributing to the corrosion may be the same, but because of the insulating characteristics of the conduit, the mitigating methods will probably be quite different. With the increasing use of concentric-neutral URD cable in duct, there is an industry need to find economic ways of mitigating corrosion of these cable neutrals.

A recent EPRI-funded three-year project with Pacific Gas and Electric Co. (PG&E) is

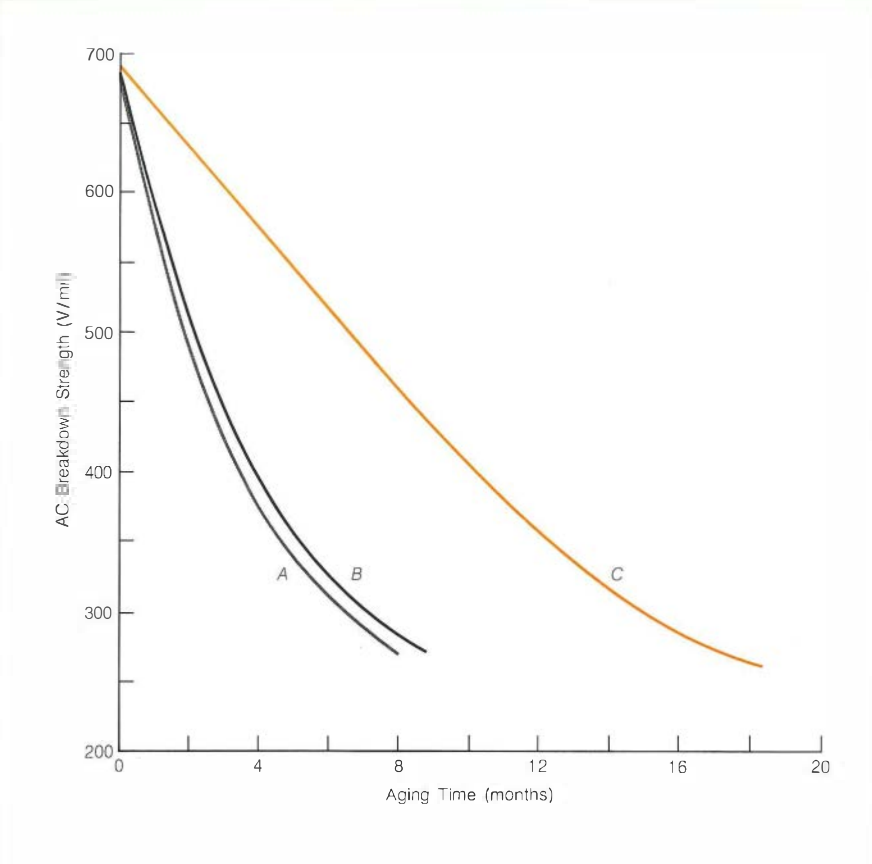


Figure 1 Dielectric strength of 15-kV distribution cables as a function of time under accelerated aging conditions. Cables tested under *A*, high frequency stresses (1000 Hz, 35–85 V/mil), and *B*, high voltage stresses (60 Hz, 85–150 V/mil), show much lower breakdown strength and shorter life than *C*, cables subjected to lower stresses (60 Hz, 35–50 V/mil).

concerned with copper concentric-neutral cables in duct (RP1771). This project will investigate, identify, and relate those mechanisms that are most important in causing corrosion under typical field conditions. Various materials, concepts, and methods that could be used to mitigate corrosion will be identified and screened for effectiveness through laboratory testing and evaluation. Those that show the most technical promise and are economical will be further evaluated in a one-year field test program. The two common situations facing utilities—existing duct installations and new cables that will be installed in duct—will be the focus of the field trials. Several diverse field trial sites will be chosen, including locations both within and outside the PG&E system.

This project will culminate in a summary report that will discuss the technical performance, cost, practicality, and field evaluation of each of the studied corrosion mitigation methods. Recommendations for mitigating corrosion of copper concentric-neutral cable in duct will also be provided. *Project Manager: Robert J. Stanger*

Estimation of cable life

In an ongoing project (RP1357-01), EPRI is using accelerated aging of energized cables in the presence of moisture to study real-world loss of cable life (*EPRI Journal*, June 1980, p. 55).

Full-size 15-kV high-molecular-weight polyethylene-insulated cables prepared at the beginning of this project in late 1978 have now been aged for as long as 20 months under conventional accelerated-stress conditions (increased voltage and/or frequency). Two results are evident from dielectric breakdown tests on cable samples periodically removed from the aging process: water-induced treeing is widespread, and ac breakdown strength in all experimental conditions ultimately levels off after an initial drop. Under a previous contract where thin-wall model cables were evaluated (RP133), the leveling-off of breakdown strength with time occurred only after treeing progressed through the entire insulation wall; results from the present project imply that leveling-off occurs earlier than this for full-size cables. The broad trend of the breakdown data for full-size cables indicates that at a 60-Hz frequency and a 35–50 V/mil average stress, retention of dielectric strength is greater than at either 60 Hz and 85–150 V/mil, or 1000 Hz and 35–85 V/mil (Figure 1).

Aging of cables will continue for up to 30 months, after which the contractor (Phelps Dodge Cable & Wire Co.) will attempt to estimate the remaining life of the aged cables by comparing the tree growth behavior of the cables subjected to accelerated aging with that of recovered field-aged cables. *Project Manager: Bruce Bernstein*

UNDERGROUND TRANSMISSION

Flexible gas cable

A project to develop a flexible, spacer-gas cable rated 345 kV is now nearing a successful completion (RP7837). It has been estimated that this cable can be at least 30% less expensive to fabricate than a comparable rigid gas cable; however, ultimate economics will vary, depending on market demand. The project will culminate with the installation of an 80-m-long prototype at the Waltz Mill Underground Cable Test Facility for at least 10 months of long-term voltage and current testing.

When last reported, a 300-mm-OD, 100-m-long prototype (rated 230 kV) had just been pulled into a trench at Waltz Mill to undergo long-term dielectric testing with cyclic and steady-state current. The prescribed test period ended with the cable energized at 200 kV, line to ground. To determine the ultimate capability of this system, the voltage was raised in increments of 25 kV a week. The system withstood a maximum of 325 kV, line to ground, for two days before it had to be deenergized for three months because of an operating problem at Waltz Mill. During this period the cable (which had already been uncovered at the end of the test period) was lifted out of the trench and placed on the surface of the ground. When reenergized, the uncovered cable failed at a severely tracked insulator. However, the test series was considered a success, as the cable not only successfully completed the desired test sequence but also withstood extreme overvoltages.

The final design for the 345-kV cable is shown in Figure 2, and its design parameters are as follows.

- Enclosure: 387 mm OD, 340 mm ID, 4 mm thickness
- Conductor: 120 mm OD, two conductors of 3 mm thickness
- Maximum stress: 3.3 kV/mm at 60 Hz, 16.8 kV/mm basic impulse level
- Power rating: 1100 MVa, buried

The insulator (spacer) is considered one of the keys to making this design a success. It is molded in two halves from an acrylic-imide copolymer, which is nontracking and exhibits good dielectric and mechanical properties up 150°C. The one precaution that had to be taken with this design was the inclusion of a molded silicon rubber pad between the insulator and the relatively soft aluminum conductor. This cushion prevents the formation of high-stress points. The system has been satisfactorily tested both on the reel and laid out straight. A 10-m-long, 345-kV prototype containing approximately 16 insulators has successfully withstood a 400-kV overvoltage test for 700 h.

An 80-m-long, 345-kV flexible gas cable prototype, the final product of this project, has been fabricated and has successfully passed six 1-min withstands at 500 kV. It has been reeled at the factory and given a 400-kV, 1-min withstand test. The reel hub is 3.35 m in diameter, and the overall diameter of the reel for shipping will be 4.22 m with cable and lagging. Once the cable has been shipped to Waltz Mill it will receive another 400-kV withstand test to determine if any severe damage occurred during shipping. The cable will then be pulled into the existing trench, and corrosion protection will be applied in place. After another 400-kV test proves that the system is ready for the long-term test period, the cable will be instrumented and buried.

As a follow-on, EPRI has funded a project to explore the potential of fabricating a higher-stressed, 500-kV flexible gas cable, using the machine that was developed for this project. *Project Manager: Ralph Samm*

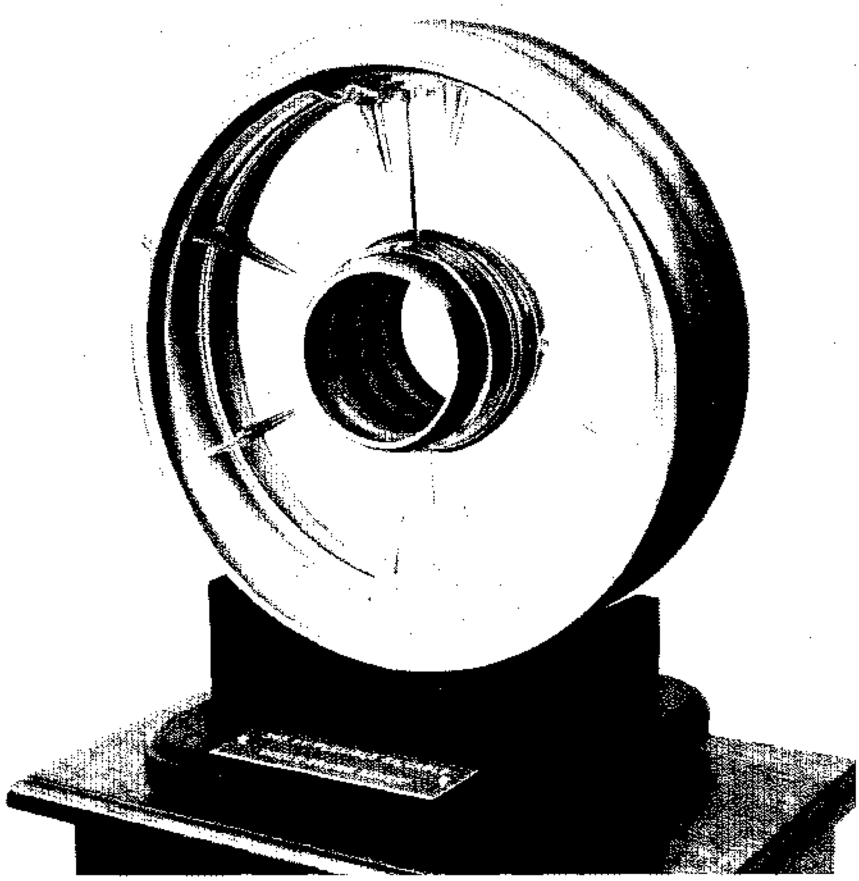


Figure 2 Final prototype design for flexible gas cable rated 345 kV; an 80-m test length has passed a 500-kV dielectric test at the factory and will be installed at Waltz Mill for long-term testing.

POWER SYSTEM PLANNING AND OPERATIONS

Power plant performance evaluation

Rising fuel costs and uncertainty of fuel supplies have prompted utility management to place increasing emphasis on performance both of the system and of individual generating units. In the next two decades, most of the customer load will be served by generating facilities that are already in operation, under construction, or for which the design is nearly complete. But because of rapidly escalating fuel costs, the cost of running fossil-fuel-fired boilers is ten times what it was three to five years ago.

EPRI is currently assessing the value of developing a demonstration test facility that uses an advanced computer-based instrumentation package in an existing fossil fuel plant. This instrumentation should provide more accurate and timely plant performance data for power system operations. Only through improved measurements, analysis and evaluation, operating procedures, and control can improved performance be achieved. It is most important to obtain accurate thermodynamic performance data, such as data on heat rate and incremental costs. Component performance data (e.g., on unit system and subsystem performance as they relate to availability and maintenance) should have high resolution and repeatability. Experience gained from the test facility would be disseminated to utilities on a regular basis during and following the tests and evaluation.

The present evaluation focuses on operating procedures; modifications in this area will eventually affect planning and design. The overall objective of this initial work is to develop the project definition, scope, and detailed work statement for a future research project that will provide the advanced, computer-based instrumentation package (RP1737). The current assessment will include descriptions of the data to be collected, the computations to be made, the tests to be run, and the quantity and format of the results obtained. The costs associated with design, installation, operation, and maintenance are also included.

FPA Corp. of Avon, Connecticut, has assembled a team of consultants to conduct this scoping study. The project began in September 1979, and the final report will be published this fall. The report will concentrate on analyses of both thermodynamic and component performance requirements for a demonstration test facility. *Project Manager: John Lamont*

Array processor power flow

Many static and dynamic power system computations are based on power flow calculations. In recent years utility engineers have experienced increased difficulty in acquiring the number of power system simulations needed to solve today's complex problems; the difficulty arises from the large amount of computer time required for such a great number of simulations, the shortage of computer storage, and cost limitations. Further, if a utility's corporate computer is also used for engineering planning studies, financial and other nonengineering tasks often take priority over engineering computations. Thus, engineers need access to other, improved computation facilities if they are to obtain solutions in a timely and cost-effective manner. Similar problems exist in real-time applications because many energy control center computers are fully utilized.

Fortunately, computer hardware has undergone many changes in the last several years, including new architecture, improved computation speeds, and reduced equipment costs. The array processor is a good example: it is low in cost and it is a peripheral device that can be attached to a general-purpose (host) computer.

The main objective of RP1710 with Boeing Computer Services (BCS) is to determine the applicability of array processors to power flow computations. BCS is restructuring the Bonneville Power Administration (BPA) power flow program to execute efficiently on an array processor. This restructuring has also been found to improve the execution efficiency on sequential computers. When the project has been completed, BCS will deliver to EPRI the original BPA program, the restructured host-only program, and the host-array processor program. The modified, host-array processor solution algorithm is being investigated for use in such applications as optimal power flow, transient stability, contingency evaluation, real-time applications, and operations control.

The second objective of the project is to determine the desirable hardware and software features for a host computer–array processor combination without regard to present market availability. The third objective is to assess the impact of an array processor with power flow software on optimal power flow computations, both now and in the future. *Project Manager: John Lamont*

OVERHEAD TRANSMISSION

Insulators for HVDC transmission lines

Two new suspension insulator designs for use with HVDC transmission lines have been completed and are being tested in the laboratory and at a dc field test station (RP1206-2). These tests will determine if a major objective of this project—to develop a dc insulator with improved resistance to the accumulation of contamination—has been achieved. If a dc insulator can successfully resist the buildup of contamination, costly insulator washings may be reduced. This is important where HVDC lines cross areas of medium-to-high air pollution.

Both designs use Polysil* (a polymer concrete) as the dielectric material. The insulators are constructed by positioning the metal end fittings in a form, pouring in the liquid polymer concrete, and allowing the material to solidify (Figure 3). This process eliminates the need for kiln firing because Polysil cures without the use of external heat. Also, cementing of the metal end fittings is not required, as they are cast within the dielectric. Therefore, this process may result in a lower manufacturing cost than that for conventional ceramic designs. However, the realization of cost reduction or the improvement of the insulators' performance in service awaits the results of further testing. *Project Manager: John Dunlap*

*Polysil is an EPRI trademark.

Transmission lines parallel to railroads

The sharing of rights-of-way by power lines, telephone lines, pipelines, and railroads has had a long and sometimes stormy history. Because of the overwhelming need to solve the problems brought on by coexistence of power and telephone circuits, considerable research was done in the early days of these industries; as a result, most of the problems arising from the proximity of power and telephone lines are well understood and capable of being solved. Another major step forward was made in a project jointly sponsored by EPRI and the American Gas Association, in which both the electric and gas utility industries examined and solved problems that can arise when gas pipelines and electric transmission lines share rights-of-way (RP742).

In a new project IIT Research Institute is identifying and developing solutions for problems that may arise when transmission lines share rights-of-way with railroads (RP1902). This project will be performed in

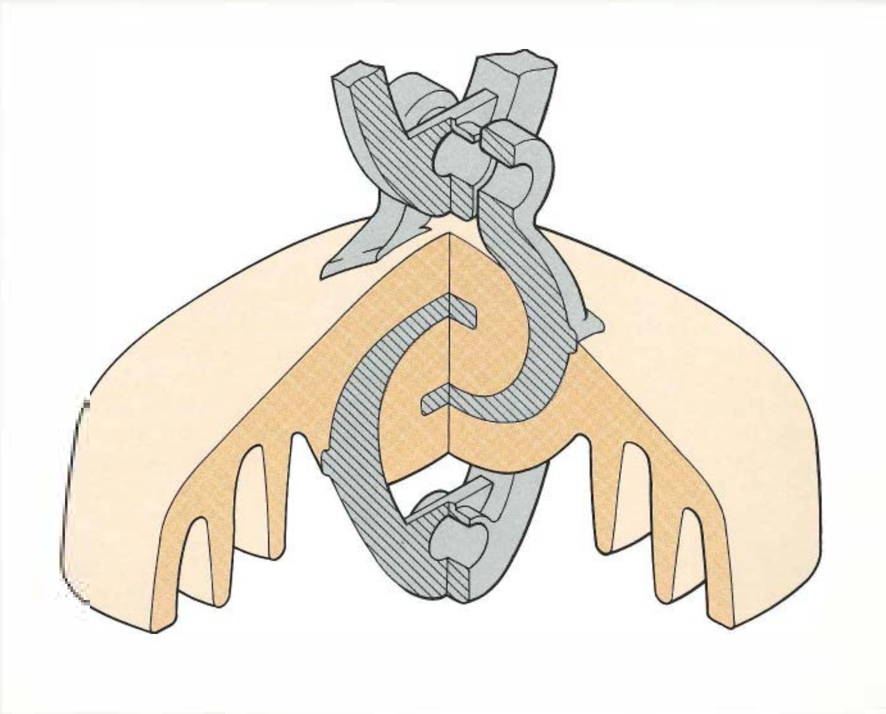


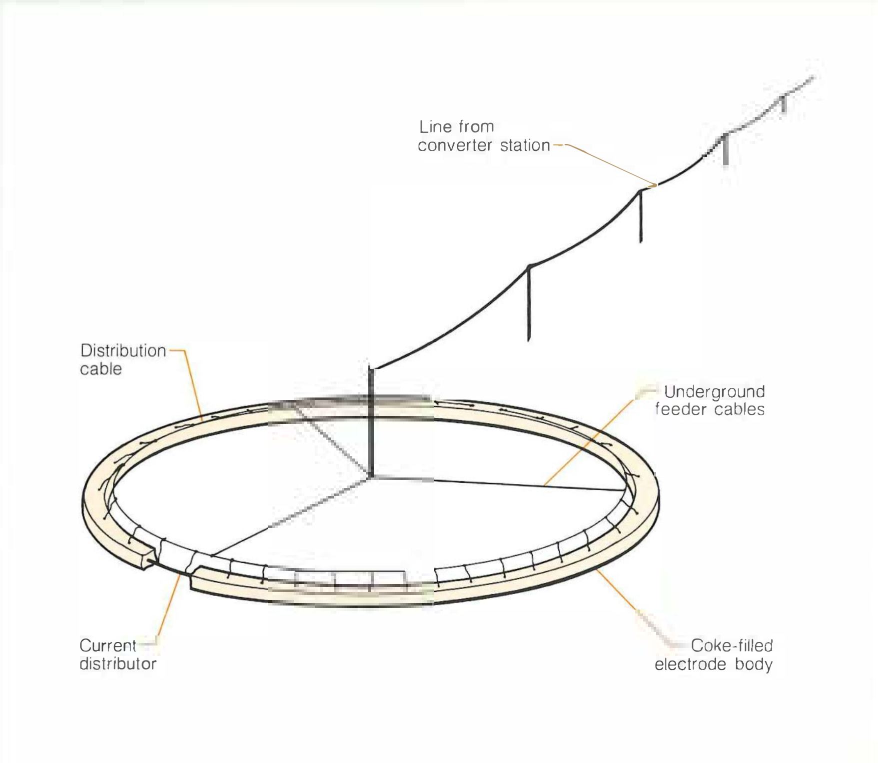
Figure 3 One of two new suspension insulator designs being developed for dc transmission lines. The insulators are constructed by positioning the metal end fittings in a form and pouring in liquid polymer concrete.

two phases, each to last one year. In phase one, the contractor will develop computer programs to accurately predict interference levels that will occur within a right-of-way containing transmission lines, communication lines, and railroad signal circuits. Since proximity of a power line to railroad facilities does not necessarily result in a problem condition, an acceptable level of interference will be identified; for the case of unacceptable interference, improved ways to reduce this condition will be developed.

Phase two will consist of laboratory tests and on-site experiments to verify the prediction techniques and mitigation methods developed in phase one. In the laboratory, commonly used railroad equipment will be tested to determine the susceptibility of each item to electromagnetic interference. These laboratory and field experiments will include tests on new communications technologies, such as fiber optics.

As a result of this project, it will be possible to accurately predict the interference a proposed transmission line will generate; reliable information on the susceptability of railroad equipment to interference will be gathered; and effective and economical mitigation techniques will be made available. This information will allow a utility considering a route near a railroad to know (in the planning stage) if interference will occur, and, if so, the cost of mitigating the problems. *Project Manager: John Dunlap*

Figure 4 Typical design of a ring electrode for HVDC grounding. With this design, the earth-return current is conducted by an overhead line from the converter station to the ground electrode, which is usually several miles away. From the middle of the ring (buried 1.2 m or more beneath the ground) the current is distributed through insulated cables to the coke-filled electrode body.



HVDC ground electrodes

This summer EPRI will publish a manual for designing HVDC ground electrodes (RP1467). For the first time, the utility industry will have a complete, up-to-date source of information for the siting and design of this important component of an HVDC line. For utilities electing to use the services of a consultant, the manual will provide the information necessary to make certain that the contractor's design is adequate, suitable for the site, and economical.

The design of an HVDC electrode (Figure 4) is quite different from that of its seemingly similar counterpart—the ac substation ground grid. Both provide an electrical connection to the ground, but their dissimilar operation makes a considerable difference in their design. One major difference involves operation during a fault. An ac ground grid must carry current for only a fraction of a second during fault conditions, and the ac line cannot operate as long as the fault condition persists. In contrast, when the positive pole on a dc line is faulted, the negative pole can continue to operate and the line carries load; however, because the earth is now the return path, the ground electrode must conduct the full load current. This condition may continue for hours (or even for days in rare cases), and the electrode must continue to operate satisfactorily. Therefore, design methods used for ac substation grounds cannot necessarily be applied to the design of a dc ground electrode.

EPRI's ground electrode design manual, being prepared by International Engineering Co., Inc., is divided into four chapters. The first chapter contains detailed information on most of the world's operating electrodes, including design, operating, and site selection criteria; electrode descriptions; and results of corrosion and interference investigations. The second chapter gives information on selecting the optimal site and describes the benefits and problems associated with a site's soil and water conditions. The third chapter shows how to best design the electrode to fit the site that has been selected. The last chapter of the manual describes tests to determine if the electrode will operate properly without interfering with pipelines, telephone circuits, or railroad signals. The manual also contains an extensive bibliography on ground electrodes, indexed by author and by subject. It is expected that this manual will be a unique and indispensable reference for utilities involved in HVDC transmission. *Project Manager: John Dunlap*

R&D Status Report
ENERGY ANALYSIS AND ENVIRONMENT DIVISION

René Malès, Director

FUTURE EFFECTS OF COGENERATION

There has been a continuous decline in the importance of cogeneration for industrial electricity as industry has relied more and more on purchased electricity. (In this report, the term cogeneration *is used loosely and includes all forms of in-plant generation by an industrial firm.) As a result of many factors primarily related to the disappearance of low-cost energy, considerable uncertainty exists about future cogeneration trends. A recently completed project in the Demand and Conservation Program will help reduce this uncertainty (RP942). The major product of this research is an engineering-econometric forecasting model that incorporates technical, economic, and institutional factors affecting industrial cogeneration decisions. One module of the forecasting system may be useful to utilities for evaluating cogeneration options at specific plants in their service areas.*

Trends in cogeneration

Industrial cogeneration is frequently mentioned as a major cost-effective conservation option. In the past, however, industrial firms have shifted away from generating their own electricity and have relied increasingly on the electric utility industry. In 1939 the manufacturing industries purchased 64% of the electricity they needed and generated 36%. By 1977 the purchased share had increased to more than 90%. During this period the quantity of purchased electricity increased 15-fold, while self-generated electricity only slightly more than doubled. The trend away from cogeneration has been especially pronounced in the past 20 years. In 1960 the generating capacity installed in industrial plants totaled 18 GW, with a slight decrease actually occurring over the past decade.

Despite the historical decline, a number of factors are focusing new attention on cogeneration.

- Increasing restrictions on the siting and operation of utility power plants and on the fuels that can be used in these plants
- Rapid increases in the price of fossil fuels
- Changes in electric utility rate structures in certain service areas, including elimination of declining-block rates and adoption of time-of-day pricing
- Proposed rules that would exempt certain industrial firms from most state and federal regulations on the sale of excess self-generated electricity
- Proposed rules that would require utilities to buy excess power and sell standby capacity at fair prices
- Proposed rules that would exempt industrial firms practicing cogeneration from regulations that require the use of coal rather than oil or natural gas in industrial boilers

Given the manufacturing sector's current heavy dependence on purchased electricity, a sudden shift to cogeneration as a result of these factors could have a considerable impact on utility loads. For example, if one-third of current industrial purchases were replaced by cogenerated electicity, utility sales would fall by about 10%. Perhaps more important, the industrial customers most likely to engage in cogeneration are those with large, steady loads. Loss of these customers could have a serious detrimental effect on utility load factors.

Forecasting model

The recently completed work under RP942 will significantly reduce the uncertainties that prevail about the future direction of industrial cogeneration. An engineering-econometric model has been developed for forecasting the use of purchased and cogenerated electricity in the manufacturing sector. The model can produce forecasts in five industrial categories: pulp and paper (Standard Industrial Classification 26), petroleum refining (SIC 29), chemicals (SIC 28), primary metals (SIC 33), and all other manufacturing. It can also provide geographic forecasts (by census region) and U.S. totals. With some additional computer code modifications, state-level forecasts could be obtained.

The key objective in formulating the model was to take into account technical, economic, and institutional factors affecting cogeneration decisions. The model was calibrated against historical data on industrial behavior. This approach was designed for determining the most likely trends in cogeneration rather than possible or preferred trends.

The user can vary important modeling assumptions in several categories, including the following.

- Tax laws and regulations
- Equipment prices
- Environmental control costs
- Economic conditions
- Industrial process demands
- Plant size distributions
- Fuel availability
- Fuel prices
- Electricity prices
- Standby capacity prices
- Buy-back prices
- Industry discount rates

Each of these categories has several variables the user can set. In the tax law category, for example, user-specified variables include corporate income tax rates, investment tax credit rates, and depreciation methods.

EPRI will make the model available to utility users on a demonstration basis through the Energy Analysis Model Applications

Center, managed for EPRI by Battelle, Columbus Laboratories (RP1814).

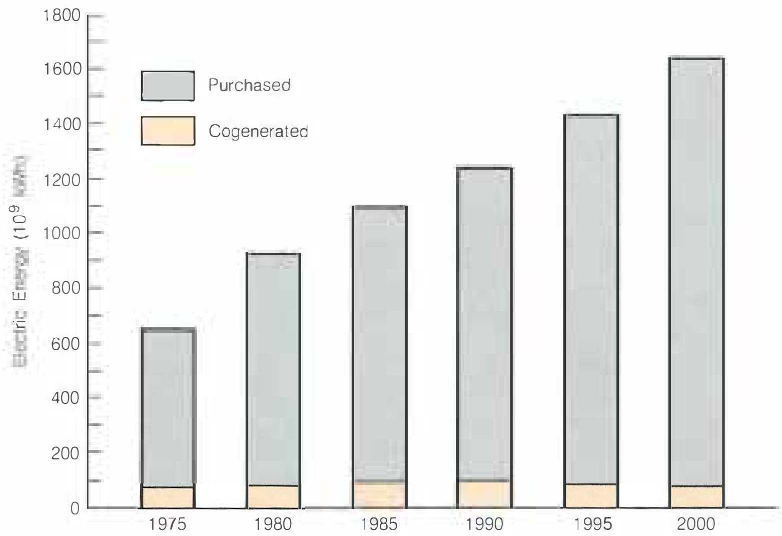
The contractor, Mathtec, Inc., has developed a trial forecast for the period 1975–2000. An attempt was made to use baseline or best-guess values for the input assumptions. As the results are very dependent on a number of these assumptions at this point the forecast should not be viewed as anything more than a demonstration.

Figure 1 shows the forecasted U.S. totals for purchased and cogenerated electricity in the manufacturing sector from 1975 to 2000. The level of cogeneration increases from 64 × 10^9 kWh in 1975 to a maximum of 101 × 10^9 kWh in 1987. It then declines to 86 × 10^9 kWh in 2000.

Perhaps more illuminating are the historical and projected average annual growth rates for industrial cogeneration. From 1939 to 1960 cogeneration grew at an average rate of 4.9% per year. There was a notable slowdown in the 1960s, when the rate dropped to 1.8%, and the slowdown turned into a decline from 1970 to 1977 (−2.4%). However, this analysis forecasts a significant turnaround during the period 1977–1987, with a projected annual growth rate of 3.8%. Cogeneration is expected to reach its peak in the late 1980s and then to decline during the rest of the century (−1.2% annual growth rate for 1987–2000).

An important feature of the forecast is the continued decline in the share of industrial electricity supplied by cogeneration. Purchased electricity is expected to grow faster than cogeneration during the entire period. Thus cogeneration's share of industrial electricity falls from 9% in 1977 to slightly more than 5% in 2000.

Figure 1 Purchased and cogenerated electricity in the manufacturing sector.



Plant energy system optimization model

One module of the forecasting framework deserves special mention—an engineering optimization model for an industrial plant energy system. This mixed-integer linear programming model (the MIP model) is designed to identify the most cost-effective methods of supplying process steam and electricity to a specific manufacturing plant. The MIP model can be used to evaluate a large number of design or operating alternatives quickly and efficiently. This screening will reduce the number of alternatives requiring detailed engineering analysis. In addition, the MIP model may be able to solve design or operating problems that are extremely difficult to solve without a sophisticated computer program.

Figure 2 illustrates how an industrial plant is simulated by the MIP model. Input information for the model consists of a description of the plant's energy requirements; a description of the energy-producing equipment in place or available for purchase; and a set of fuel, purchased-electricity, equipment, and finance cost. The model is able to determine which equipment should be used (or purchased), how the equipment should be operated at any given time, how much the system and its operation will cost, and how much fuel and purchased electricity will be consumed.

The MIP model may be of value to utilities interested in conducting screening studies to identify potential cogenerators in their service areas or studies to evaluate how

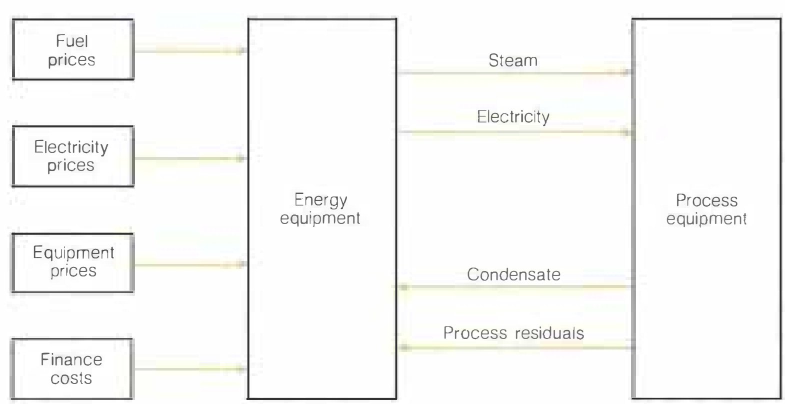


Figure 2 The MIP engineering optimization model uses data on costs, equipment, and energy requirements to determine the most economical methods of supplying an industrial plant with process steam and electricity. The engineering requirements for electricity, condensate, and process residuals vary with time; steam requirements are a function of both time and pressure.

cogeneration decisions are affected by alternative rates, including rates for electric power (time-of-day pricing and declining block), rates for steam, rates for standby capacity, and buy-back rates for cogenerated electricity. Utilities can also use the model to help customers evaluate cogeneration opportunities, steam and power equipment replacement options, and load-shifting options.

It should be noted that the MIP model requires solution software not generally available. Interested utilities should contact the project manager for further details. *Project Manager: Larry Williams*

NO_x GUIDANCE MANUAL

Several new regulations have been promulgated that are likely to affect the permissible nitrogen oxide (NO_x) emissions from fossil fuel power plants; moreover, other regulations are possible. Because utility experience with NO_x regulations is fairly limited, EPRI has sponsored the preparation of resource material to bring together the state of knowledge on the issue (RP1375). This is expected to improve the ability of the industry to respond to the new regulations. This material consists of a guidance manual that summarizes available NO_x information and a six-volume technical support document that provides in-depth background information. Together, these publications outline the scientific tools available to the industry for complying with the regulations in the context of key NO_x-related regulatory changes and their implications.

Regulatory background

The Clean Air Act Amendments of 1977 mandated regulations in three areas that will have a bearing on the needed degree of control of NO_x emissions from power plants. These involve setting a short-term (averaging time of three hours or less) standard for nitrogen dioxide (NO_2); establishing PSD (prevention of significant deterioration) regulations for NO_2, which limit the incremental contribution new sources may make to ambient NO_2 levels in areas of low pollution; and reducing visibility impairment in areas defined as Class I visibility areas (national parks, monuments, and wilderness).

These regulations have not yet been precisely defined, but their impact could be considerable. For example, if the short-term NO_2 standard is set at a one-hour average of 0.25 ppm (an intermediate value being considered by EPA), current-design coal-fired power plants larger than 1250 MW (e) that satisfy new-source performance standards could not comply. The effects of the pending PSD regulations could be even more severe. If these regulations are promulgated by the same procedures used in setting the PSD increments for sulfur dioxide (SO_2) and total suspended particulates, it may not be possible to build a coal-fired power plant of current design larger than 350 MW (e), even if the plant satisfied current new-source performance standards. In some cases, visibility regulations could place greater constraints on the siting of large power plants than the current PSD regulations. The contribution of NO_x emissions to visibility effects in PSD Class I areas may necessitate site-separation distances substantially greater than those required by the SO_2 limits in the same areas.

In addition to the short-term NO_2 standard, PSD, and visibility regulations, new regulations affecting NO_x control are possible in two other areas: ozone concentration levels and acid rain. As NO_x can be a precursor to both ozone and acid rain, control efforts in these areas could entail more-stringent restrictions on NO_x emissions from power plants.

Resource documents

In view of the potential significance of the pending NO_x-related regulatory changes, the utility industry must be prepared to respond to them. The implications of the changes for plant siting and planning must be understood; changes in the regulatory environment must be anticipated; and the options available to the industry, particularly with respect to air quality modeling and control technology, must be delineated. In an effort to help utilities in these areas, EPRI is publishing two related documents: an NO_x guidance manual for air quality modeling (planning, siting, and emissions control) and a comprehensive six-volume reference containing technical support information.

The manual is in a loose-leaf format designed to provide the utility industry with a comprehensive reference for dealing with the new regulations. It is intended to serve several specific purposes. In the first section, the important implications of the pending NO_x-related regulatory changes are examined in the context of utility planning. The second section presents important background material on regulations and the issuing of permits. The third section covers NO_x control technologies.

Subsequent sections examine the state of scientific knowledge on NO_x effects and modeling. These sections explain the role of NO_2 air quality impact analysis and define an NO_x modeling effort that is technically adequate, yet no more extensive than necessary. The expected effect of the new NO_2 air quality standards on site screening and selection is discussed, and procedures are suggested to help satisfy the regulations. The manual also presents methods for evaluating the performance of air quality models and describes data and resource requirements, as well as data availability.

The technical support volumes play an important supplementary role, and they are heavily referenced in the guidance manual. Volume 1 presents an introduction, and volumes 2–6 cover the following topics, respectively: legislative and regulatory environment, physical atmospheric phenomena relevant to NO_x concentration, mathematical modeling of atmospheric NO_x, emissions control technology, and applying NO_x air quality models. In addition to NO_x per se, visibility issues are discussed throughout the publication.

One important conclusion of the material presented is that substantial benefits can be realized by selecting the most appropriate air quality model for NO_2; model selection is more critical for NO_2 than for other regulated pollutants. Simple models are typically based on the total conversion assumption, which holds that all NO_x is emitted as NO_2. But NO_2 actually makes up only about 5–10% of a power plant's emissions, and the conversion of NO after it has left the stack may not be total; hence the total conversion assumption will lead to the overestimation of downwind concentrations, particularly for short-term averages. It follows that this conservative assumption may also overstate the need for NO_x control. To help avoid this problem, the guidance manual includes a suggested methodology that uses decision trees to identify appropriate types of NO_2 and visibility models. *Project Manager: Ronald Wyzga*

R&D Status Report
ENERGY MANAGEMENT AND UTILIZATION DIVISION

Fritz Kalhammer, Director

COMPRESSED-AIR ENERGY STORAGE

Compressed-air energy storage (CAES) plants are ready to become cost-effective contributors to utility generation systems in the United States. Such plants can be built in approximately 220-MW unit sizes and constructed in the short time of 3–5 years. EPRI's work on CAES has included (jointly with utilities and DOE) preparing preliminary engineering designs for CAES plants that use salt domes, rock caverns, and aquifer geologic reservoirs for storing air; developing and analyzing advanced CAES designs that reduce the plant fuel requirements; and investigating unresolved issues (such as the "champagne" effect) to assist utilities in comparing CAES with other near-term alternatives for meeting peak and cycling needs.

A CAES plant incorporates modified state-of-the-art combustion turbines and site-specific underground reservoirs to store off-peak energy for later use during peak demand periods. The generator, normally coupled with the combustion turbine to generate electricity, is replaced with a motor-generator; this dual-purpose machine operates in different modes during different time periods. During an off-peak period, relatively inexpensive energy from coal-fired and/or nuclear baseload units powers the motor to compress air, which is then stored in an underground reservoir. During the subsequent peak period, the compressed air is withdrawn from storage and mixed with fuel; the combustion gases created by burning this mixture are expanded through turbines connected to the motor-generator to produce power. Because the turbine is not required to drive a compressor during the peak time period (which it must do in a conventional combustion turbine system), a CAES unit reduces the use of petroleum- or gas-based fuels by more than 60%.

A 290-MW (50-Hz) CAES plant using salt-dome caverns is currently operating in Huntorf, Federal Republic of Germany, providing peak-leveling duty for the German utility Nordwestdeutsche Kraftwerke Ag (Figure 1). This plant was built by BBC Brown Boveri and Co., Ltd., and was commissioned in December 1978. Its performance has equaled or exceeded the design specifications (98% availability, 99% starting reliability).

For applications in the United States, the plant design must be converted from 50 Hz to 60 Hz, include an exhaust heat recuperator to minimize fuel requirements, and accommodate the charge-discharge requirements of U.S. utilities. EPRI contracts have thus addressed these and other near-term issues to enhance domestic commercialization.

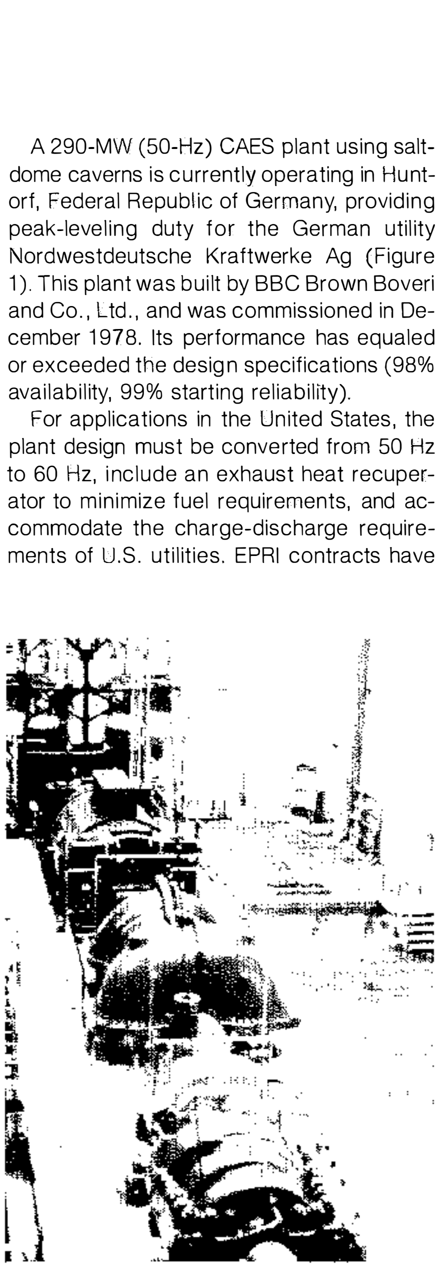


Figure 1 Turbomachinery of the 290-MW (50-Hz) salt-dome CAES plant in Huntorf, Federal Republic of Germany. The success of this plant has provided the major impetus for efforts to commercialize a similar system in the United States.

Preliminary design studies

EPRI, DOE, and individual utilities have sponsored detailed preliminary engineering design studies of CAES since 1977 (RP1081-1, -2, and -3). Projects were initiated with Potomac Electric Power Co. (Pepco), Middle South Services, Inc. (MSS), and Public Service Indiana (PSI) to investigate (respectively) the use of hard rock caverns, salt domes, and aquifer reservoirs for containing the compressed air. The Pepco project also investigated hard-rock caverns in an underground pumped storage application. The first two projects have been completed. The Pepco report has been published (EM-1589), and the MSS report will be available soon. Publication of the PSI study is not expected until late this year.

The overall objective of each project was to provide firm estimates of cost, schedule, and degree of technical risk on which a decision to construct a CAES plant can be based. The task efforts included the development of plant design criteria; screening and selection of a suitable site; development of machinery design approaches; identification of environmental issues and licensing requirements; development of overall plant design, cost estimates, and construction schedules; and development of data on the trade-offs between direct costs, operating costs, and date of installation. Although each project was carried out on a specific utility system, the projects are documented in such a way that another utility can use the results generically to determine the potential benefits and costs pertinent to its system. Study results (Table 1) confirm the near-term technical and economic viability of the CAES technology and provide a basis for utility decisions on this near-term energy storage option.

Table 1
CAES PLANT: DESIGN AND COST

	Pepco Plant	MSS Plant
Type of cavern	Rock (water-compensated)	Salt (solution-mined)
Type of cycle	Daily	Weekly
Rating (MW)	924 (4 units)	221 (1 unit)
Cavern volume (yd^3)	785,000	1,300,000
Air storage pressure (atm; MPa)	75; 7.6	75; 7.6
Turbine heat rate (Btu/kWh)	4015	3980
Charging energy ratio (kWh in/kWh out)	0.74	0.78
Direct cost (1979 $/kW)	379	326

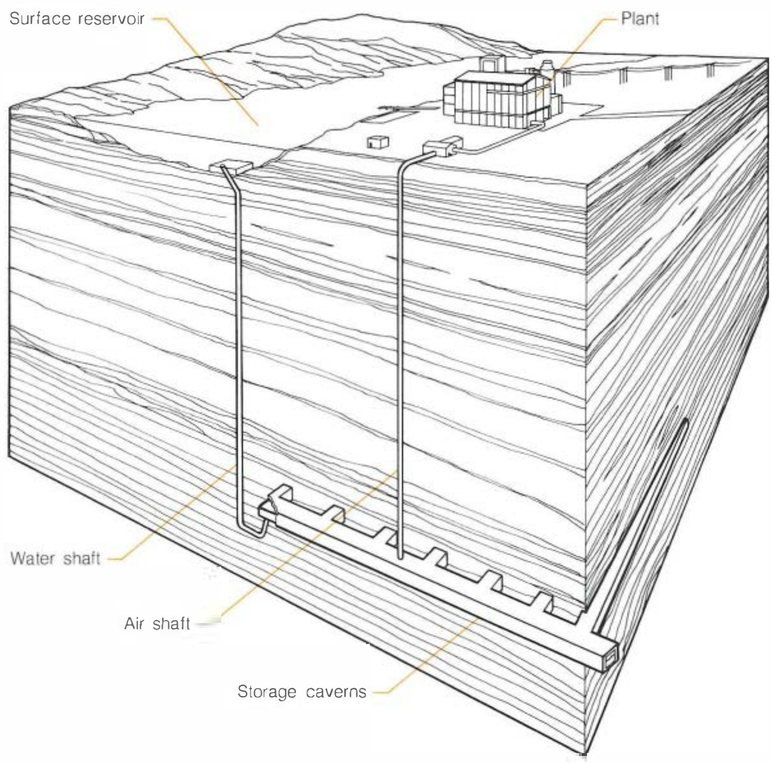


Figure 2 The CAES plant investigated by Pepco under RP1081-1 uses hard-rock caverns for storing air. Note that the storage cavern is compensated to a constant air pressure by a surface reservoir and water shaft.

For the Pepco utility system (Figure 2), three CAES units with a total capacity of 675 MW (e) would conserve approximately one million barrels of oil per year and save $1.4 billion (in 1980 dollars) over the next-best generation alternative.

Advanced CAES

EPRI has investigated advanced CAES plant concepts in an attempt to reduce the fuel requirements of the first-generation U.S.-based CAES plant studied under EPRI RP1081 (a 60-Hz Huntorf-type plant with an exhaust heat recuperator). A near-term hybrid concept for further study was identified in a screening of such concepts completed by the Central Electricity Generating Board (EM-1289). This concept uses a pebble-bed thermal store to retain a portion of the heat of compression from the CAES charge cycle, which is subsequently used to reheat the stored compressed air during the generation cycle. Such an advanced CAES cycle is estimated to reduce the oil or gas fuel consumption of the plant by approximately 33%. To properly assess the near-term feasibility of this concept, EPRI retained United Engineers & Constructors, Inc., to develop detailed preliminary engineering design specifications and costs for this type of plant. The project is complete and the final report is expected to be published late this year. The thermal store consists of 0.5-in-diam ceramic spheres housed in an internally insulated, posttensioned concrete pressure vessel. The ceramic spheres are made of a high-density silica-alumina material called denstone, which is manufactured by the Norton Co. and usually used for catalyst bed support in refinery applications. During the normal compression-generation cycle, the denstone spheres cycle between 204°C (400°F) and 490°C (916°F). The hybrid advanced CAES system adds about 25% additional direct $/kW cost to the conventional plant costs, increases the charging electric energy by approximately 34%, and reduces the oil or gas fuel costs by approximately 33%. After accounting for these credits and debits, the levelized busbar costs remain about the same as for the conventional CAES plant.

EPRI has asked utilities for their judgment (on the basis of data from the preliminary analyses) as to whether this advanced concept warrants further investigation. In addition, a detailed laboratory assessment is being performed on the capability of the thermal store materials to withstand the cycling environment posed by the plant specifications for this advanced concept.

Issues affecting conventional CAES

The conventional CAES technology is likely to be commercialized in the United States in the very near future. One utility, Soyland Power Cooperative, is currently negotiating contracts to have a 220-MW (e) plant installed and operating by the middle or late 1980s. EPRI is directing R&D support toward solving potential problems so that this and similar projects can be kept on a cost-effective schedule. At present, there are two such concerns. The first is with the durability of the exhaust heat recuperator and its ability to operate with minimal maintenance costs in the high-pressure, cycling environment of a CAES plant. The second concern is with the rock cavern, water-compensated CAES plant (Figure 2), where there may be a need to enhance the control algorithm of the plant and/or extend the U-tube at the bottom of the water shaft. This issue arises because of a possible flow instability during the charge cycle caused by air bubbles that evolve from the air-saturated water in the water shaft.

Preliminary CAES design improvements have been proposed to deal with these issues, and present work is focused on acquiring the detailed data needed to finalize methods for cost-effectively resolving them. *Project Manager: Robert Schainker*

SCREENING OF LOW-HEAD HYDRO SITES

EPRI has supported the development of a relatively simple, inexpensive procedure for the initial screening of small-capacity hydroelectric sites (RP1199-5). This procedure, developed by Tudor Engineering Co., will permit utilities to identify and evaluate possible sites; analyze their potential; rank them in order of technical, economic, and institutional feasibility; and select those most attractive for continued investigation. The project's final report (EM-1679) is a manual that describes step-by-step procedures to estimate a site's power and energy output, evaluate the probable cost of developing a potential site, and perform preliminary economic analysis. The manual covers plant capacities ranging from 0.2 to 15 MW and heads ranging from 2 to 60 m (6–200 ft).

Continuing increases in the cost of producing electric power have led to a reevaluation of small-capacity hydroelectric resources. Particular attention is being given to generation from hydroelectric sites that had previously been identified but were considered to be uneconomic or too small to be worth developing. *Small hydro* normally refers to projects with capacities below 15 MW and heads of up to 20 m (65 ft).

A preliminary U.S. Army Corps of Engineers study in 1977 found a potential 55 GW of power available at existing installations—about half at small-hydro sites. However, the study identified sites on the basis of theoretical possibility and did not consider economic feasibility, environmental impact, or competing water use; it is now apparent that economically and environmentally acceptable small-hydro power sites are substantially less common than this and other similar surveys have projected.

Although hydroelectric engineers and planners still believe that a significant number of existing and new sites can be developed, evaluating and ranking these sites can be expensive, especially as many sites are likely to be rejected after preliminary evaluation. Even the evaluation of locations where it may be possible to install an additional turbine to recapture lost energy (from water presently spilled) can represent a substantial expenditure for engineering planning. Costs of such studies can range from $5000 to $10,000 a site.

Recognizing that this problem can limit small-hydro development, EPRI established a project to assist utilities interested in this resource (RP1199-5). The specific objectives of this project were to develop a simplified analytic methodology and prepare a procedures manual for performing first-level evaluations of the feasibility of potential sites for small-capacity hydroelectric power plants. (The manual does not include micro-hydro plants, which have capacities of less

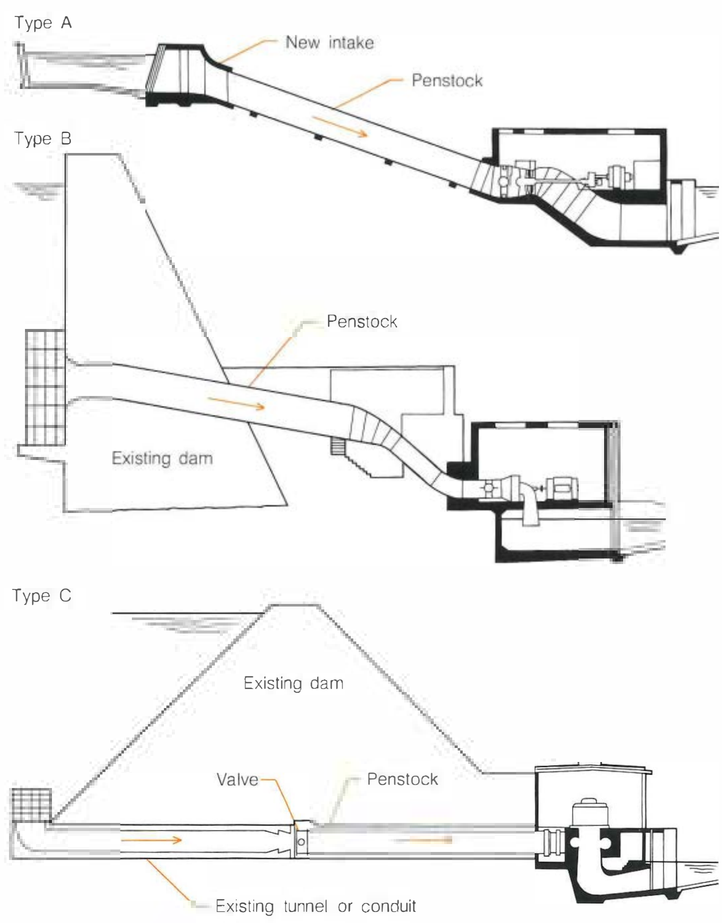


Figure 3 Standard hydroelectric plant Types A, B, and C; Type D is a combination arrangement in which the power plant acts as (or is part of) the dam or spillway. Various turbine types can be used in these configurations.

than 150 kW.) The procedures are intended primarily for use by personnel who have a limited background in hydroelectric engineering.

Types of hydroelectric plants

A proposal to develop a small hydroelectric plant is usually prompted by the existence of a site with a head drop and supply of water sufficient to generate power in practical amounts. A rough approximation of required heads and flows can be calculated from the following equation.

$$\text{Capacity} = \frac{(\text{head})\,(\text{flow})}{14}$$

Here, the capacity is in kilowatts, the head is in feet, and the flow is in cubic feet per second. Thus a head of 14 ft and a flow of 1000 ft^3/s result in a capacity of 1000 kW.

Often sites that have been identified include a dam built for other purposes or a power generation dam no longer in use; supply canals with sudden drops represent another possibility. Because the cost of extensive headworks is a significant factor in hydro project economics, most small-hydro plants are likely to be developed at sites where another facility already exists.

When power is to be developed at an existing dam or other drop in a stream, the project will fall into one of the following general categories (Figure 3).

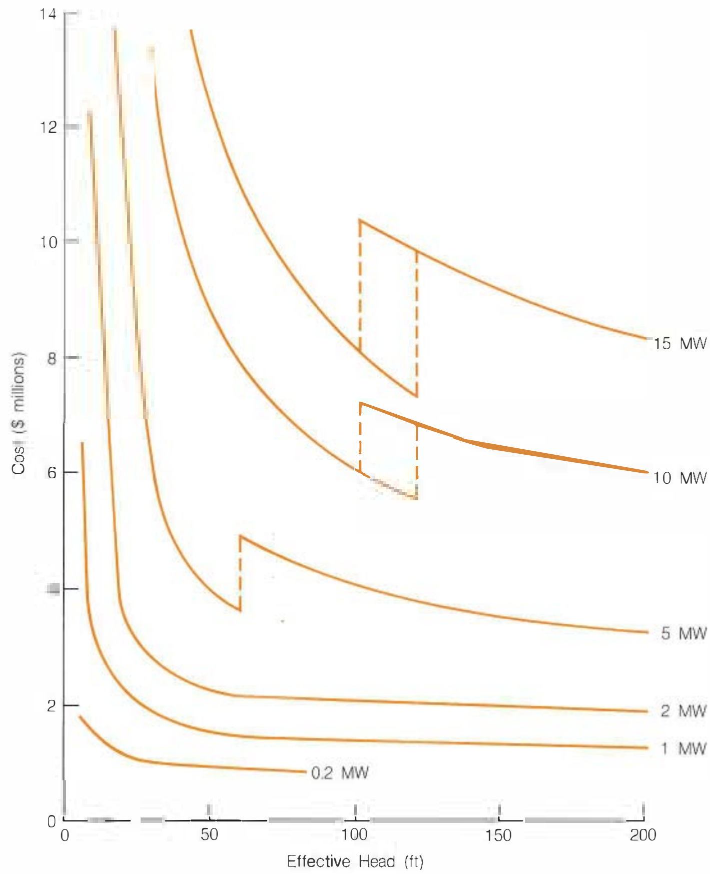
- Type A involves a new intake structure, penstock, and powerhouse. An approach channel to the intake and a tailrace connecting the power plant to the river or other channels may be necessary. The intake may be located at a dam or on a channel.
- Type B involves a new independent power plant attached to the downstream end of an existing conduit in a concrete dam or intake structure.
- Type C involves a new independent power plant attached at the downstream end of an existing tunnel or conduit with a discharge valve located mid-length on a concrete conduit or at the end of a steel conduit.
- Type D is a combination arrangement in which the power plant acts as, or is part of, the dam or spillway. This type usually involves upgrading an existing power plant.

These categories describe the situations normally encountered and the ones for which costs were developed under RP1199-5.

Project costs

The probable capital costs of a power project may be estimated from the power plant capacity and effective head: Figure 4 can be used for projects that are categorized as Type A, B, or C, and a similar curve can be used for Type D projects. These capital costs include direct construction costs, contingencies, engineering, construction management, administration, and interest during construction. Costs are based on installation of a typical hydroelectric plant at an existing facility and assume the use of the least expensive turbine and power plant arrangement for each head and capacity.

Figure 4 Minimum capital costs, as of April 1979, for single-unit hydroelectric power plants of Types A and C; the costs for a Type B installation are 7% lower. Cost increases caused by the need to use a different type of turbine are indicated by dashed lines. Estimates do not include the costs of land, land rights, access roads, bridges, relocations, special environmental provisions, or transmission lines.



Tudor Engineering has compared the results obtained with the techniques presented in the manual developed under RP1199-5 with the results of several detailed small-hydro engineering feasibility studies and has found them to be consistent in terms of evaluating and ranking plant arrangements and sites. In addition, the equipment and civil cost data in the manual were developed from sources also used by the more detailed manuals of the U.S. Army Corps of Engineers and the U.S. Water and Power Resources Service. Thus, given comparable project conditions, the EPRI manual and the more detailed manuals should produce similar cost estimates and results. EPRI is confident, therefore, that the manual will adequately guide utilities with small technical staffs through a preliminary (reconnaissance-prefeasibility) analysis, furnishing a basis for them to confidently decide whether to proceed with more detailed analyses by qualified technical personnel. It is estimated that using the manual for a preliminary analysis of a site will take about a week and cost hundreds instead of thousands of dollars. The exact cost will depend, however, on the amount of hydrological data available. *Project Manager: Antonio Ferreira*

R&D Status Report
NUCLEAR POWER DIVISION

John J. Taylor, Director

REMOTE PIPE REPAIR WELDING

The repair of piping in an operating nuclear plant presents major problems in terms of personnel radiation exposure and plant outage time. An integrated equipment system has been developed to permit remote control of the repair operations—pipe severing, weld preparation machining, and replacement pipe welding. The system promises to reduce personnel radiation exposure substantially, decrease plant downtime, and improve the quality of repairs.

System requirements

The occurrence of IGSCC in nuclear reactor piping has necessitated the replacement of failed components in operating plants. It is difficult to obtain high-quality welds under the working conditions in these plants. A major problem is radiation exposure. To avoid exceeding prescribed radiation limits, each person is allowed to be in the work area for only a brief period; thus it is necessary to use a large number of workers. Obtaining enough trained welders to make a major repair has been a serious problem in some geographic areas. Another problem is that access to a failed component in these plants is limited, and workers must wear cumbersome protective equipment.

In response to these problems, EPRI initiated a project with Battelle, Columbus Laboratories to develop an integrated system for semiremote repair operations (RPT108). The basic advantages of a semiremote system are that its equipment can be installed in the radiation area in a brief period of time (preferably by less highly skilled workmen), and equipment operation can be controlled almost entirely by personnel located outside the radiation area. Operations to be performed by the system include severing the pipe, machining the end of the remaining pipe, fitting the new pipe or component in place, and completing the welding. Postwelding inspection capability is also required.

Machining the old pipe, which includes beveling and counterboring, must be done to a true circle geometry so the pipe will fit properly with the newly machined replacement pipe. Variations in roundness and wall thickness of the old pipe need to be considered; otherwise, the machining may remove so much metal that minimum wall thickness requirements are not met. Then the pipe has to be built up by weld cladding in an additional costly and time-consuming operation. The pipe's external dimensions and the wall thickness around the entire circumference must be measured precisely to enable calculation of the optimal center for machining the pipe weld. Ideally this should be done before severing the pipe because the radiation level in the work area increases markedly when the irradiated corrosion products within the pipe are exposed. Thus provision for the remote measurement of these dimensions is another system requirement.

Battelle was directed to use, as much as possible, commercially available units for the basis of the system. This policy permitted development work to be concentrated in those areas where the needed equipment was not available; it will also facilitate transfer of the system technology. Other aims of the project were to set specifications for needed equipment and to assess the relative advantages of different repair equipment presently available to the nuclear industry.

System features

Development of the integrated repair system was recently completed. Details on the system's gaging, machining, welding, and control components follow.

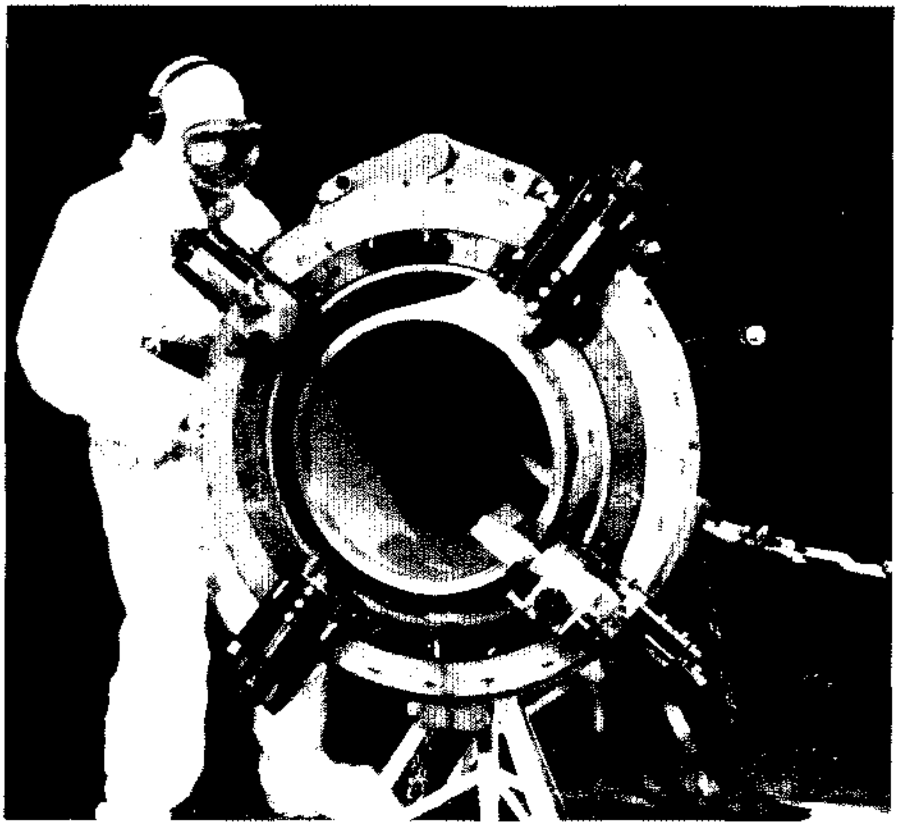
Pipe wall thickness and variations in roundness are measured by two transducers: an ultrasonic transducer and a linear variable-differential transformer (LVDT) radial displacement transducer attached to the welding track. The track carries these gaging instruments around the pipe and also acts as a reference surface. The recorded information is transferred to a computer, which determines the optimal centering position for the counterboring tool and the wall thickness that will result. This allows all tool positions to be preset, including the centering position for the lathe used to minimize wall thickness loss during counterboring. All the measurements can be made remotely once the gaging equipment is mounted on the track.

Two machining systems were developed, one for 12-in (30-cm) pipe and the other for 20–26-in (51–66-cm) pipe. The first incorporates a guillotine-type saw for severing and an axial-feed lathe mounted inside the pipe. A power feed for the saw was designed and built to permit remote control of motor operation and cutting rate. The internally mounted lathe was constructed with an adjustable mandrel to permit off-center machining and was modified for remote operation.

The system chosen for 20–26-in (51–66-cm) pipe has an externally mounted lathe that incorporates tools for both severing and machining (Figure 1). Two parting tools mounted 180° from each other are used for severing. Beveling and counterboring are accomplished without repositioning the lathe by two other, separately mounted, single-point tools with axial and radial feeds. Again, the equipment was modified for remote operation. This unit has the advantage that minimal in-reactor adjustments are necessary once the lathe is initially positioned on the pipe. One problem, however, is the large clearance the unit requires, which restricts the number of reactor weld joints where it can be used.

The welding equipment represents a major portion of the total system. Battelle chose a mechanized gas-tungsten arc welding unit consisting of a power source, a weld programmer, tracks for a variety of weld diameters, and a welding head that travels around the outside circumference of the pipe (Figure 2). Although it is possible to preprogram all the welding parameters (e.g., current, magnitude, and time of transweld oscillation; pulsing; travel speed; and wire feed), the process must be monitored by an operator who can alter electrode position or other

Figure 1 A machinist in protective clothing checks operation of the external lathe for severing and machining pipe in preparation for a new weld.



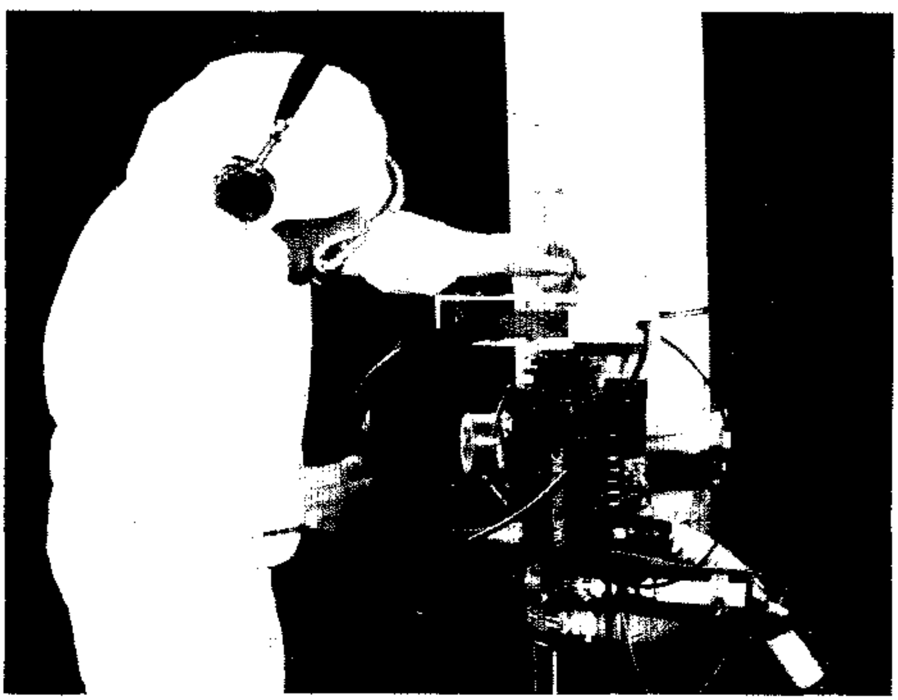


Figure 2 Installation of an automatic welding machine on a 12-in vertical pipe.

parameters as is necessary to ensure a satisfactory weld.

To enable an operator to control the welding process while remaining outside the high-radiation area, a small television camera was mounted on the welding head. The camera provides a close-up view of the arc itself and the solidifying pool of weld metal behind the arc; its images are conveyed to the viewing monitors by a dual fiber optic system. A masking system was developed to moderate the intense light from the arc so details of the weld pool can be seen. Although not optimal, the clarity of the images provided by the television system is sufficient for remote control of the welding operation. Modifications are now being made to improve the images.

To supplement the television system, a multichannel display of electrical parameters is provided. A unique feature of this auxiliary system is an XY recorder that continuously shows the position of the electrode tip. The geometry of the weld preparation region and the weld deposit can be outlined by this instrument. Some welds have been made remotely with this system alone (i.e., without using television monitors); further enhancements contemplated for follow-on work may make possible a fully adaptive remote-welding control system.

Many changes were made in the commercial machining and welding equipment selected for the system to adapt it for remote operation and for installation by personnel encumbered by radiation protection clothing. Warning indicators, including lights and audible signals, were added to ensure safety during remote operation. A television camera is used to monitor the work area, and a zoom lens enables close inspection of individual operations.

Technology transfer and further development

It is believed that this project has developed concepts and equipment for reactor piping repair that will improve the quality of welds while reducing plant availability losses, repair costs, and personnel radiation exposure. Such a system will also help solve the often critical problem of obtaining a sufficient number of trained welders to accomplish a major welding repair in a radiation area.

The complete remote-welding system has been transferred to the BWR Owners Group Pipe Remedy Demonstration and Training Facility at EPRI's Nondestructive Evaluation Center in Charlotte, North Carolina, where it will be further refined and used for instruction and planning for actual plant repair and maintenance. Just before the system was shipped to the center, Battelle demonstrated its various components to representatives from utilities, reactor vendors, architect-engineers, equipment manufacturers, and service organizations. This presentation was the first step in the process of technology transfer.

Evaluations of the equipment studied in this project, along with feedback from industrial personnel currently involved in reactor repair operations, will serve as the basis for further system development. A key objective of future work will be the development of lighter, more compact machining equipment that is better suited for use in the very restricted areas typical of operating nuclear plants. *Project Manager: Wylie Childs*

SAFETY MARGINS OF CRACKED STAINLESS STEEL PIPE

Intergranular stress corrosion cracking (IGSCC) of type-304 stainless steel piping in BWRs is a significant problem because of the inspection and repair costs it entails and the concern it raises about the possibility of large releases of radioactive coolant caused by a loss of piping integrity. Considerable progress has been made toward resolving the most important integrity issues associated with IGSCC. Present evidence strongly suggests that the most probable consequence of undetected IGSCC is a slow leak and that BWR piping configurations make unstable fracture very unlikely. Moreover, in some cases it may be justified to defer repairing a pipe with a part-through crack to minimize the impact of the repair on plant availability.

IGSCC in weld-heat-affected zones of stainless steel BWR coolant piping (Figure 3) was initially observed at Dresden Unit 1 in the mid-1960s and has continued to be a problem since that time. Until quite recently, cracking was confined to small-diameter lines—e.g., the 4-in (10-cm) discharge valve bypass line—for which loss of integrity is not a major concern. In the summer of 1978, however, circumferential IGSCC was observed in both furnace-sensitized safe ends and weldments of 26-in (66-cm) recirculation outlet piping at a German BWR. Leaking cracks had already been observed in 12-in (30-cm) recirculation riser piping in Japan. Because the consequences of a loss of integrity in such large-diameter, high-energy piping could be severe, U.S. utilities and regulatory agencies responded rapidly to these reports. In 1979 EPRI, with funding from the BWR Owners Group, initiated a project (RPT118) to address two of the most important questions raised by IGSCC: Is leak-before-break behavior assured in the event of IGSCC? If a part-through crack caused by IGSCC is detected by in-service inspection, does the cracked pipe have any remaining useful life or is immediate repair required?

Leak-before-break behavior

Under normal service loads, IGSCC in weld-heat-affected zones is expected to result in leak-before-break behavior. Cracking must affect a very large fraction of the pipe cross section in order to extend the crack by ductile tearing. It is predicted that well before the cracked area reaches this size, the azimuthal variations of welding residual stresses and material susceptibility in the weld-heat-affected zone, combined with the applied bending loads, will lead to asymmetrical crack growth and to the formation of a through-wall crack at some location. This prediction is borne out by field experience: to date, all the cracks from IGSCC that have penetrated the pipe wall have resulted in a leak and have been detected well before there was any chance of pipe failure under normal service loads.

A more important issue involves the safety margin of a cracked pipe and the potential for break-before-leak behavior in the event of an abnormal load (resulting from, say, an earthquake). Analytic and experimental studies have shown that stable crack growth from ductile tearing starts when a critical plastic flow stress is reached in the pipe cross section. Delineating the transition be-

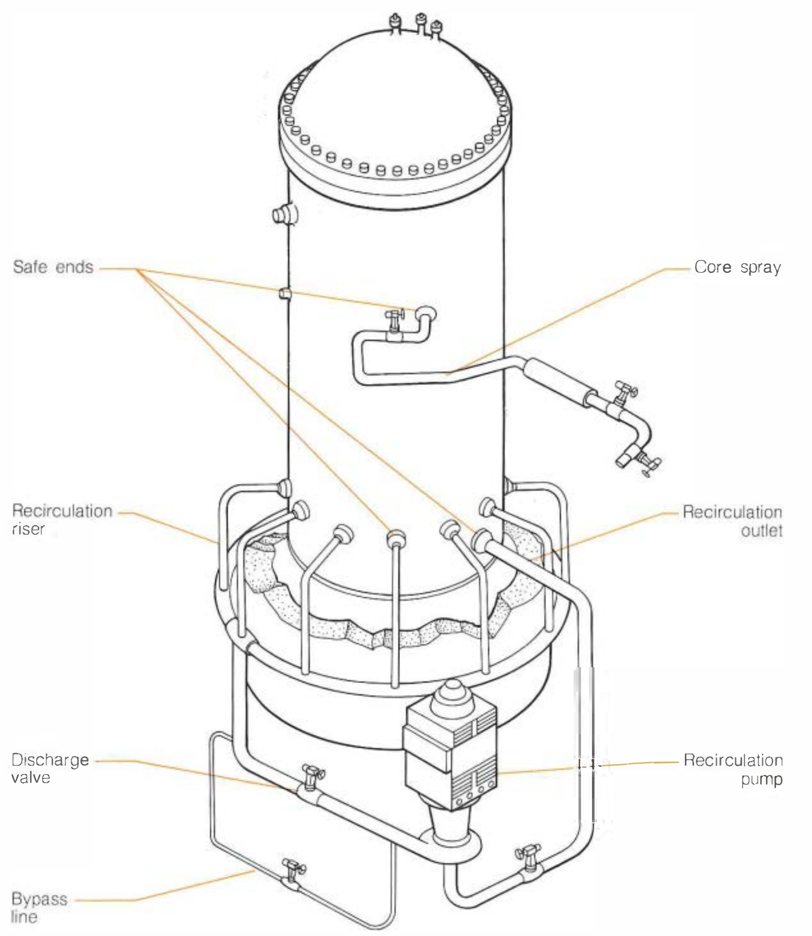


Figure 3 Schematic of a BWR showing parts of the recirculation and core spray piping systems. IGSCC has been observed adjacent to welds in these stainless steel systems.

tween this stable tearing and unstable pipe fracture is the critical aspect of the leak-before-break question.

Substantial progress has recently been made in elastic-plastic fracture mechanics. For structures made from very tough ductile materials, such as stainless steel, it is now known that the occurrence of unstable fracture (which would lead to break-before-leak behavior) is determined by how the fracture resistance (a material property) and the crack driving force (which depends on load and structural geometry) vary with crack extension. Because laboratory measurements have determined how the fracture resistance of stainless steel varies with crack extension, predicting crack growth instability becomes a matter of predicting how the driving force varies as the crack extends through the wall and around the circumference of the pipe.

Under NRC sponsorship, a stability analysis has been performed for a circumferentially flawed stainless steel pipe subjected to severe displacement-controlled bending, a condition believed to be generally representative of seismic loading. The analysis showed that instability was unlikely if the pipe length-to-diameter (L/D) ratio was less than 100. More recent work sponsored by NRC and EPRI (RPT118-9) has shown that L/D values for the BWR coolant systems that have suffered IGSCC are well below 100. Thus it appears that instability is very unlikely under large loads characterized by displacement-controlled bending, even in the presence of severe IGSCC.

The validity of the approach to structural instability taken by the NRC analysis was demonstrated in small-specimen tests. Further verification was recently obtained in an EPRI-sponsored bend test on a flawed 4-in (10-cm) stainless steel pipe (RPT118-2). In this test, which was conducted at Battelle, Columbus Laboratories, the specimen was spring-loaded to simulate a length of ~30 ft (9 m). The results confirmed the transition from stable to unstable crack growth predicted by the stability analysis.

EPRI is sponsoring additional stability tests in which pipes with part-through and through-wall flaws are being subjected to combinations of internal pressure, bending, and axial tension to simulate piping loads under normal and abnormal operation. Other work is seeking to obtain estimates of the crack driving force and its variation with crack extension for a variety of geometries and loads and to develop simple methods of determining equivalent L/D values for the complex piping systems found in BWRs.

Repair or replacement timing

The observation of rapid crack propagation in the small-diameter pipes involved in early IGSCC incidents led to the belief that IGSCC always propagates rapidly. Accordingly, the response to IGSCC detection has been immediate repair or replacement. Recent research, however, like that reported in NP-1163, has revealed that crack propagation rates are strongly influenced both by the residual stress distribution in the weld-heat-affected zone and by the location of crack initiation. It now seems likely that with IGSCC of large pipes, the safety margin of the cracked pipe is sufficient to warrant deferring the repair until its effect on plant availability is minimal (e.g., until the next refueling outage). A decision to defer repair must be supported by the following.

- A conservative assessment of the maximum allowable crack size and the time necessary for the crack to reach this limit
- A method of continuously monitoring crack growth or a conservative plan for intermittently sizing the crack
- Leak-before-break assurance and sensitive leak-detection capability

All these requirements are being studied in ongoing EPRI projects. Progress toward leak-before-break assurance has been described above; nondestructive methods for leak detection and intermittent crack sizing are available and are being upgraded; and methods for the continuous monitoring of crack size are being developed and are expected to be available by mid-1982. In addition, a simple procedure for specifying the maximum allowable crack size has been developed by General Electric Co. (RPT118-1) and verified with both field and laboratory data. The procedure is illustrated in Figure 4.

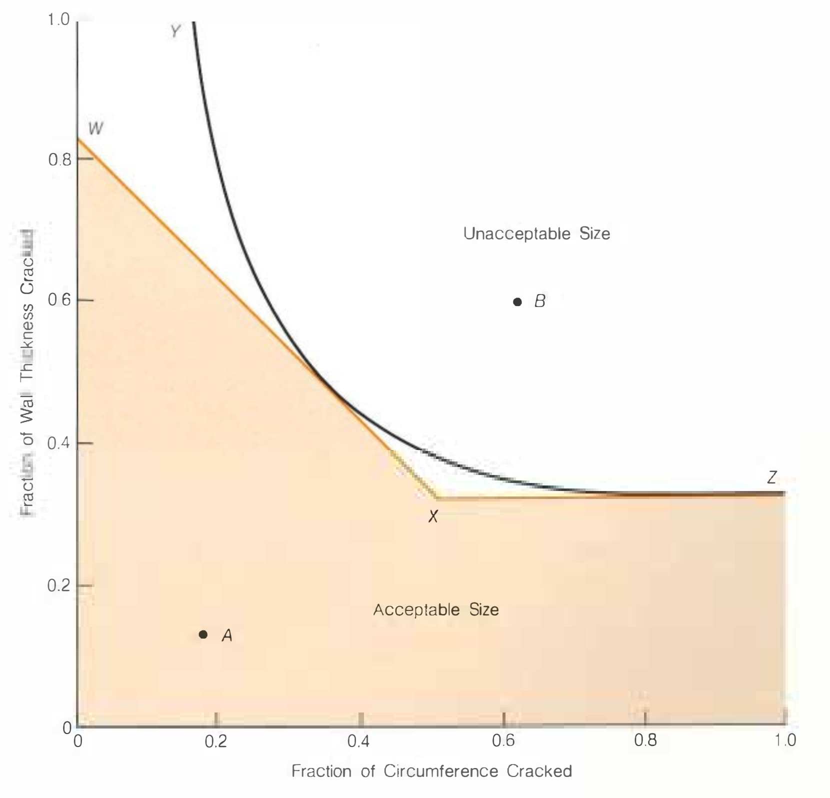
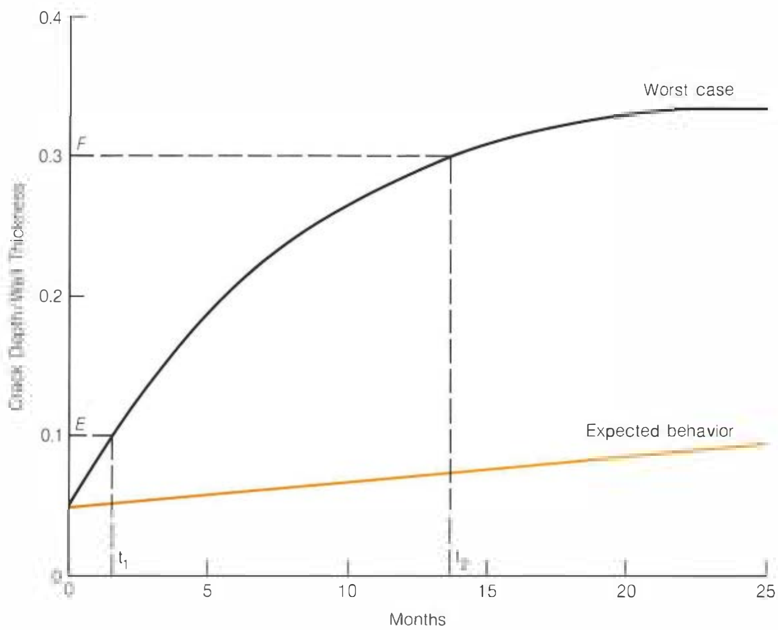


Figure 4 Simple procedure for establishing the maximum allowable flaw sizes in cracked stainless steel piping. The plastic collapse locus *YZ* is obtained from equilibrium considerations, with a safety factor of 3 on upset operating stresses. The maximum allowable flaw sizes are defined by line *WXZ*, which is obtained by drawing horizontal (*XZ*) and 45° (*WX*) tangents to the collapse locus. Cracks with sizes lying in the shaded area (e.g., Point *A*) are acceptable for some period of continued service, whereas those lying in the unshaded area (e.g., Point *B*) require immediate repair.

Figure 5 Method of estimating the remaining useful life of a cracked, 26-in-diam, schedule 80 type-304 stainless steel pipe. A measured stress distribution through the wall of the pipe is used to obtain a driving force versus crack depth curve. This is combined with two growth rate versus driving force curves obtained from small-specimen tests to yield two estimates of crack depth as a function of time, shown here. Then if the current ratio of crack depth to pipe thickness is E and the maximum allowable ratio is F, the remaining life is $t_2 - t_1$. The calculation shows that the crack driving force falls below that required for continued IGSCC when the ratio of crack depth to thickness reaches 0.35.



An estimate of a cracked pipe's remaining useful service life is needed to determine the value of considering repair deferment and to establish a schedule for in-service inspection, if that is the method chosen to monitor crack growth. In terms of Figure 2, it is necessary to estimate how long it will take for a crack whose dimensions are defined by a point in the shaded area to reach line *WXZ*, which defines the maximum allowable flaw size. Although the growth rate of stress corrosion cracks is difficult to predict exactly, estimates can be made on the basis of data developed in RPT118 and other EPRI projects (Figure 5). Crack growth predictions obtained in this way confirm that crack propagation in as-welded small-diameter lines is so rapid that immediate repair is recommended if IGSCC is detected by in-service inspection. On the other hand, because welding residual stress distributions are more favorable in large-diameter pipes, periods on the order of years are predicted to be necessary for a small crack in, for example, a recirculation outlet line to grow to a point at which the remaining safety margin would be unacceptable. Thus, it may be justified to defer repairs in large-diameter lines until scheduled refueling outages in order to minimize plant downtime. Crack growth verification experiments on full-size pipe samples subjected to simulated service conditions are in progress at General Electric Co. (RPT118-1) and Battelle, Pacific Northwest Laboratories (RPT106-1). *Project Managers: Robin Jones and Douglas Norris*

New Contracts

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
Advanced Power Systems				
RP1319-7	Advanced Cooling, Full-Scale Engine Demonstration	18 months	434.7	Westinghouse Electric Corp. *A. Cohn*
RP1654-8	In Situ Measurement of Coal Conversion Kinetics in an Entrained-Flow Reactor	13 months	56.3	Advanced Fuel Research, Inc. *G. Quentin*
RP1801-1	High-Reliability Combustor System	26 months	822.9	General Electric Co. *H. Schreiber*
RP1923-2	Role of Design Complexity in Forecasting Reliability	8 months	70.7	ARINC Research Corp. *J. Weiss*
Coal Combustion Systems				
RP1260-2	Comparative Economics of Dry/Wet Heat Rejection Systems	1 year	50.0	Robert D. Mitchell, PE *J. Bartz*
RP1402-4	Electrostatic Precipitator Sizing and Design Guidelines	9 months	74.4	Charles Gallaer, PE *W. Piulle*
RP1685-4	FGD Sludge Disposal Manual, Update No. 2	13 months	94.2	Michael Baker, Jr., Inc. *D. Golden*
RP1836-2	Feasibility Study of Japanese Low-NO_x Burner	7 months	88.1	Combustion Engineering, Inc. *M. McElroy*
RP1852-2	On-Line Slurry Ash and Sulfur Analysis by X-Ray Fluorescence	10 months	35.8	Harrison Cooper, Inc. *R. Sehgal*
RP1852-6	On-Line Analysis of Coal Slurries by Neutron Activation	9 months	54.1	Science Applications, Inc. *R. Sehgal*
RP1895-2	Combustion Tests of Coal-Water Mixture	5 months	30.0	Babcock & Wilcox Co. *R. Manfred*
Electrical Systems				
RP668-3	Evaluation of Electronic Current Transducer for HVDC Systems	10 months	15.0	General Electric Co. *S. Nilsson*
RP1143-2	Eliminating Destructive Failure in Distribution Transformers, Phase 2	22 months	566.1	McGraw-Edison Co. *R. Stanger*
RP1359-6	Logic Model Analysis: Evaluating System Design Specifications	3 months	5.0	Andtek, Inc. *S. Nilsson*
RP1768-2	Development of a SF_6 Gas Density Monitor, Phase 2	4 months	15.7	Technology Dynamics *V. Tahiliani*
RP1902-1	Design of Overhead Transmission Lines and Railroad Communications	26 months	568.4	IIT Research Institute *J. Dunlap*
RP7876-13	Compaction of Amorphous Ferromagnetic Metal Powders	3 months	10.0	SRI International *M. Rabinowitz*
Energy Analysis and Environment				
RP1630-16	External Coordination for Regional Air Quality Studies	10 months	62.8	Morton L. Barad *G. Hilst*
RP1826-3	Risk Assessment Methodology for Pollutants	6 months	10.0	Battelle, Pacific Northwest Laboratories *P. Ricci*
Energy Management and Utilization				
RP1201-14	Performance Monitoring of Groundwater-Source Heat Pumps in the Northeast	2 years	44.8	Allegheny Rural Electric Cooperative *J. Brushwood*
Nuclear Power				
RP606-8	Development of Prototype Pressure Vessel Imaging System	2 years	1034.5	Sigma Industrial Systems, Inc. *J. Quinn*
RP695-4	RETRAN Analysis of the RB-2 Stability Tests	10 months	19.7	Oregon State University *J. Naser*
RP1171-3	Effects of Oxygen and Oxidizing Ions on Denting	2 months	50.0	Central Electricity Generating Board *R. Vansanik*
RP1333-04	Evaluation of Explosive Welding of Tube to Tubesheet Joints	6 months	51.1	Aptech Engineering Services *W. Childs*
RP1385-2	Analysis of Arkansas Nuclear One, Unit 2, Tests with RETRAN	10 months	51.4	Middle South Services, Inc. *J. Naser*
RP1447-2	Chromatography Systems for In-Plant Monitoring	2 years	124.9	American University *T. Passell*
RP1928-1	Moisture Separator Reheater and Feedwater Heater Performance Monitoring	30 months	339.0	Southwestern Engineering Co. *M. Kolar*
RP2014-2	Forces From Fluid Annuli on Pump Shaft	6 months	30.4	Science Applications, Inc. *C. Chan*
Research and Development Staff				
RP1678-5	Technical, Economic, and Utility Systems Analysis Support to R&D Planning Evaluation	1 year	60.0	Decision Focus, Inc. *O. Gildersleeve*

New Technical Reports

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

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

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ADVANCED POWER SYSTEMS

Catalytic Combustion of Coal-Derived Liquid Fuels

AP-1666 Final Report (RP989-3); $6.50

This report describes a laboratory study that investigated the feasibility of catalytically burning currently available coal-derived liquids. Tests were conducted with three state-of-the-art catalytic reactors and three fuels: No. 2 diesel (for baseline data) and the coal-derived liquids H-Coal and SRC-II. The results indicate that coal-derived liquids can be burned catalytically, but state-of-the-art catalysts are prone to deactivation. The contractor is Acurex Corp. *EPRI Project Manager: L. C. Angello*

Industrial Oxygen Plants: A Technology Overview for Users of Coal Gasification–Combined-Cycle Systems

AP-1674 Final Report (RP239-5); $4.50

This report presents an overview of the technology associated with commercial oxygen production, focusing on the technical and economic aspects. Details are provided on the development and current status of industrial oxygen production; oxygen plant process and equipment; process control, including contaminant removal and heat exchange; plant operation and reliability; production costs; and environmental, safety, and health considerations. The contractor is Union Carbide Corp. *EPRI Project Manager: B. M. Louks*

High-Reliability Gas Turbine Combined-Cycle Development Program: Phase 1

AP-1681 Final Report (RP1187-3); Vol. 1, $12.50; Vol. 2, $12.50

Volume 1 presents the results of Tasks 1 and 2 of the first phase of this program. Task 1 assessed the reliability potential of the General Electric MS7000 gas turbine engine in a combined-cycle application; the results were used to estimate the expected baseload performance. In Task 2 tradeoff studies for major components examined reliability versus key design parameters—cost, performance, firing temperature, metal temperatures, and emission capabilities. Volume 2 presents the results of Tasks 3–6. These tasks focused on a conceptual plant design featuring a centerline high-reliability gas turbine; recommended R&D programs for major component technology; modifications for converting a baseload machine into a peaking and midrange turbine; and potential retrofits. The contractor is General Electric Co. *EPRI Project Manager: R. L. Duncan*

Assessment of Transport Barriers to Tritium Migration Through Fusion Reactor Materials

AP-1696 Final Report (TPS76-561); $3.50

This report describes a theory for estimating tritium migration through materials. It also presents the results of a small-scale experiment aimed at illuminating the basic processes of tritium migration under simulated fusion reactor conditions. Details on the experimental procedures are included, as well as new measurements of tritium permeation at very low partial pressures and a surface characterization of a permeation barrier of type-304 stainless steel. The contractor is Princeton University. *EPRI Project Manager: N. A. Amherd*

Proceedings of the Fourth Annual Geothermal Conference and Workshop

TC-80-907 Conference Proceedings; $10.50

A conference-workshop was held in June 1980 in Monterey, California, to report results of EPRI- and utility-sponsored geothermal research and to discuss the topic of learning from power plant experience. U.S. and international geothermal power plant development was reviewed, and a special presentation was made on the Baca demonstration plant project. Workshop discussions focused on financing, technical performance, and environmental control. The contractor is Altas Corp. *EPRI Project Manager: V. W. Roberts*

COAL COMBUSTION SYSTEMS

Kramer Station Fabric Filter Evaluation

CS-1669 Final Report (RP1130-1); $10.50

Results are presented from a nine-month evaluation of the fabric filtration system at Nebraska Public Power District's Kramer station, the first system to be applied to pulverized-coal-fired utility boilers burning a western low-sulfur subbituminous coal. A three-phase field performance test program was conducted, involving baghouse "as-found" tests, tests to determine an improved baghouse cleaning cycle, and evaluations of fine particle and trace element emissions when a preferred cleaning cycle was in effect. An engineering and economic analysis is included. The contractors are Meteorology Research, Inc., and Stearns-Roger Engineering Corp. *EPRI Project Managers: R. C. Carr and M. W. McElroy*

Atmospheric Fluidized-Bed Combustion Development Facility

CS-1688 Final Report (RP718-1); $12.50

This report documents the design and construction of a 6-by-6-ft coal-fired atmospheric fluidized-bed combustion (AFBC) test facility. It describes the AFBC and auxiliary equipment, the control system, the analytic equipment, and the computerized data acquisition system. Also summarized are the operating problems encountered during startup and initial testing and the corrective actions taken. The contractor is Babcock & Wilcox Co. *EPRI Project Managers: C. J. Aulisio and T. E. Lund*

Failure Cause Analysis: Fans

CS-1693 Final Report (RP1265-6); $5.75

This report presents the results of a survey to identify power plant fan problems and their causes and effects. The various fan types (forced draft, induced draft and scrubber booster, flue gas recirculating, and primary air) and their major components are described. Recommendations are made to improve the reliability of existing fans, and generic problems requiring future research and the application of current technologies are identified. The contractor is Fan Systems Co. *EPRI Project Manager: I. A. Diaz-Tous*

Structure and Stability of Coal-Oil Mixtures and Coal-Water Mixtures

CS-1695 Final Report (RP1030, RP1455-6); $3.50

The structure and stability of coal-oil mixtures (COMs) and coal-water mixtures were evaluated. This report describes the techniques for COM evaluation developed during the study—sedimentation, subsidence, pycnometry, and solvent extraction—and summarizes the findings. Details are provided on the development and improvement of a sedimentation column apparatus for the screening of COM stabilizers. The contractor is the University of Massachusetts. *EPRI Project Manager: R. K. Manfred*

The Otisca Process: A Pilot Plant Study of Dense Liquid Separation

CS-1705 Final Report (RP1030-15); $4.50

This report presents the results of a pilot plant study of the Otisca coal-cleaning process, a dense liquid separation process. Distribution curves, probable errors, error areas, and organic efficiencies were calculated from data obtained in a test run. The process, the pilot plant facility, and the experimental procedure are described. On the basis of sharpness-of-separation criteria, the Otisca process is superior to others using heavy-media cyclones, hydrocyclones, and concentrating tables. The contractor is Otisca Industries, Ltd. *EPRI Project Manager: R. S. Sehgal*

Assessment of Control System Technology Used in Fossil-Fuel-Fired Generating Plants
CS-1718 Final Report (RP1266-15); $5.75

A study was undertaken to assess the control system technology used in fossil-fuel power plants and to identify areas where advanced control system methodologies could be applied to improve plant performance. Current power plant control system design practices were examined in the light of dynamic operating conditions, such as occur in cycling, and were compared with the capabilities offered by modern multivariable systems design and analysis procedures. The contractor is Analytic Sciences Corp. *EPRI Project Manager: J. P. Dimmer*

ENERGY ANALYSIS AND ENVIRONMENT

Analysis of Field Test Data on Residential Heating and Cooling
EA-1649 Final Report (RP1364-1); $5.75

In follow-on work on the residential energy analysis program (REAP) model, field site test data were used to further validate and improve the computer program. This report discusses the feasibility of expanding the model's capabilities and describes the refinements and corrections made to the original model, including modified subroutines to improve the accuracy, stability, and speed of the calculations. Graphic and statistical analyses of comparisons between predicted results and measured data are also presented. The contractor is Battelle, Columbus Laboratories. *EPRI Project Manager: Edward Beardsworth*

Validation of Plume Models: Statistical Methods and Criteria
EA-1673-SY
Summary Report (RP1616-1); $2.75

This report presents the findings of a workshop held in January 1980 to define statistical methods for use in plume model performance evaluation. The workshop was principally concerned with the assessment of model performance in predicting ground-level concentrations and the use of model predictions as a basis for regulatory decision making. The difficulties or constraints imposed on validation efforts by data limitations are outlined. The contractor is TRC–Environmental Consultants. *EPRI Project Manager: G. R. Hilst*

Rationale for Quality Precipitation Chemistry Sampling
EA-1682-SR Special Report; $4.50

This report discusses the rationale behind procedures used in precipitation chemistry monitoring and outlines procedural modifications suggested by field experience in current major networks. Procedures in these areas are covered: site selection and preparation, field operations, laboratory analysis, and quality assurance. The report includes a copy of the EPRI-Rockwell network operating manual and a sample quality assurance plan. *EPRI Project Manager: J. J. Jansen*

Intermediate-Term Uranium Supply Curve Estimation
EA-1706 Final Report (RP1294); $8.25

A study was undertaken to estimate U.S. natural uranium supply capacities and associated production costs over the period 1979–1990 and to develop the general supply outlook to 2000. Annual supply capacity schedules were estimated on an individual mill and mine family basis. Future production schedules were estimated by balancing estimated supply capacity with DOE's future demand projections; the impact of private-sector inventory levels was accounted for. The contractors are International Energy Associates, Ltd., and David S. Robertson & Associates, Inc. *EPRI Project Manager: J. H. Eyssell*

ETA–MACRO: A User's Guide
EA-1724 Interim Report (RP1014); $5.75

This user's guide includes an overview of the ETA–MACRO model, an illustrative application projecting long-term U.S. economic growth, and technical descriptions of the ETA and MACRO submodels. An analysis of how market penetration rates may be related to the profitability of new technologies is summarized. The model inputs are described, and a detailed guide to computer implementation is provided. The contractor is Stanford University. *EPRI Project Manager: E. V. Niemeyer*

ENERGY MANAGEMENT AND UTILIZATION

Oxygen Reduction on Supported Pt Alloys and Intermetallic Compounds in Phosphoric Acid
EM-1553 Final Report (RP1200-5); $4.50

Toward the goal of developing improved electrocatalysts for acid fuel cell applications, several intermetallic catalysts of platinum and a Group IVb or Vb metal were prepared and evaluated in terms of stability and oxygen reduction. The contractor is Lawrence Berkeley Laboratory. *EPRI Project Manager: A. J. Appleby*

Stability of Acid Fuel Cell Cathode Materials
EM-1664 Interim Report (RP1200-2); $3.50

This report presents results from a study of the stability of electrode materials used in hot phosphoric acid fuel cells—specifically, the stability of the conductive carbon electrocatalyst support and the platinum-based electrocatalyst particles. The effects of several parameters on the corrosion rates of various carbon substrates in hot phosphoric acid were investigated, and tests examined the loss of surface area of platinum supported on carbon under fuel cell operating conditions. The contractor is Stonehart Associates, Inc. *EPRI Project Manager: A. J. Appleby*

Commercial Solar–Load Management Experiment: New Mechanical Engineering Building
EM-1680 Interim Report (RP844-2); $2.75

A two-year monitoring program is under way at the University of New Mexico's mechanical engineering building to determine the effects of load management heat recovery, thermal storage, and solar systems on energy use and power demand profiles. This report describes the building's heating and cooling systems, the monitoring instrumentation, and the computer-based data acquisition system. A modified version of the AXCESS energy analysis program for simulating building energy use is detailed, and the development of preferred strategies for maximizing the building's load management capabilities is discussed. The contractor is Public Service Co. of New Mexico. *EPRI Project Manager: T. M. Lechner*

Effects of Sulfur-Containing Gases on the Performance of Molten Carbonate Fuel Cells
EM-1699 Interim Report (RP1085-2); $3.50

The effects of sulfur-containing anode and cathode gases on molten carbonate fuel cell components and performance were examined at sulfur levels in the range of 1–10 ppm. Sulfur impurities considered were H_2S or COS in low-Btu fuel gas and SO_2 in oxidant gas. Cell performance recovery after low-level sulfur excursions, which could occur during failure of the sulfur removal subsystem, was studied. The contractor is the Institute of Gas Technology. *EPRI Project Manager: A. J. Appleby*

Stability of Kocite Electrocatalysts in Phosphoric Acid Fuel Cells
EM-1711 Final Report (RP1200-3); $4.50

This report summarizes the results of a two-year program to characterize and improve the stability of Kocite electrocatalysts in phosphoric acid fuel cells. The experimental procedures, conditions, and analyses are described. The contractor is UOP, Inc. *EPRI Project Manager: A. J. Appleby*

Introduction of Electric Vehicles Into the Utility System: Analysis of Research Needs
EM-1716 Final Report (RP1524-2); $3.50

The objectives of this study were to identify potential impacts on utility systems of a large-scale introduction of electric vehicles (EVs) by the year 2000 and to make recommendations for EPRI research to assist utilities in accommodating EV loads. A review of EV penetration predictions is included. The contractor is Systems Control, Inc. *EPRI Project Manager: G. H. Mader*

Development of Zinc-Bromine Batteries for Utility Energy Storage
EM-1717 Interim Report (RP635-2); $6.50

This report presents results from a project to develop and analyze full-size zinc bromide cell hardware for utility energy storage applications. It describes the building and testing of two monopolar submodules and one bipolar submodule, and details the successful conversion from monopolar to bipolar cell design. It also presents a cost-design study of an 80-kWh stand-alone module, as well as studies performed in support of battery design, construction, and testing. The contractor is Gould Inc. *EPRI Project Manager: W. C. Spindler*

Evaluation of Transient Voltage Suppressors for Saving Electric Energy
EM-1722 Final Report (RP1201-11); $4.50

This report evaluates studies that have been conducted by others to determine whether transient voltage suppressors save energy. Field, laboratory, and theoretical studies were reviewed; the so-called amplification mechanism (by which it is suggested the device saves energy) was analyzed; and commercial devices were examined. The report concludes there is no convincing proof to support claims that transient voltage suppressors alone save electric energy. The contractor is Alexander Kusko, Inc. *EPRI Project Manager: R. J. Ferraro*

EPRI–SCE Testing and Evaluation of Electric Vehicles: Lucas Van and Jet 007, 750, and 1400

EM-1723 Annual Report (RP1136-1); $4.50

This report describes the second phase of a test program to develop a data base on state-of-the-art electric vehicles. Data on physical characteristics, range, acceleration, payload capability, and field reliability were obtained for four vehicles under real-world driving conditions involving various traffic densities, terrains, and payloads. The report describes vehicle component failures that occurred during testing and presents assessments of expected field reliability. The contractor is Southern California Edison Co. *EPRI Project Manager: R. J. Ferraro*

Workshop on Electrodes for Flowing-Solution Batteries

WS-79-192 Workshop Report; $3.50

This report summarizes a workshop on electrodes for flowing-solution batteries that was sponsored by EPRI and DOE in Tampa, Florida, in November 1979. The topics covered are current distribution in flow-through porous electrodes (FTPEs), conversion efficiency, segmented-FTPE studies, FTPE parameters, surface activation, application of FTPEs to waste recovery, Exxon's zinc-bromine flow-by system, FTPEs in NASA redox energy storage, and application of FTPEs in Lockheed's zinc-ferricyanide redox system. The contractor is SRI International. *EPRI Project Manager: W. C. Spindler*

NUCLEAR POWER

LOCA Hydroloads Calculations With Multidimensional Nonlinear Fluid-Structure Interaction: STEALTH 2D–WHAMSE 2D Single-Phase Fluid and Elastic Structure Studies

NP-1401 Final Report, Vol. 2 (RP1065); $8.75

This volume describes alterations and refinements in the two-dimensional STEALTH and WHAMSE computer programs, as well as single-phase fluid studies, structural studies, and fluid-structure interaction studies. The contractors are Intermountain Technologies, Inc., Science Applications, Inc., and Northwestern University. *EPRI Project Manager: R. N. Oehlberg*

BWR Refill-Reflood Program: Core Spray Distribution Experimental Task Plan

NP-1523 Interim Report (RP1377-1); $3.50

The core spray distribution experimental task plan of the BWR refill-reflood program is summarized. A description of the experimental facilities, a specification of the test matrix, test results obtained for the BWR-6 (218) geometry, and a test schedule are presented. The contractor is General Electric Co. *EPRI Project Manager: Mati Merilo*

Transport of Fuel and Fission Products From Failed Mixed-Oxide Fuel Pins by Flowing Sodium in LMFBRs

NP-1609 Final Report (RP620-25-5); $4.50

This report describes the transport of fuel particles and fission products from failed LMFBR fuel pins and the deposition of radioactive materials in the primary sodium coolant system. Such transport and deposition could increase personnel radiation exposure and become a limiting factor in the operability, inspectability, and maintainability of piping and equipment in primary coolant cells. The contractor is Argonne National Laboratory. *EPRI Project Manager: R. K. Winkleblack*

Conceptual Design of a 1000-MW (e) Heterogeneous Oxide LMFBR

NP-1616 Final Report (RP620-32); Vol. 1, $9.50; Vol. 2, $13.50

A numerical core and blanket design for a 1000-MW (e) LMFBR that has a reduced sodium void coefficient of reactivity has been developed. Volume 1 discusses the design assumptions, ground rules, and methodology, and it describes the various assemblies and the core layout. It also summarizes nuclear, thermal-hydraulic, and fuel-life analyses of core performance. Design details and the results of various trade-off, sensitivity, and optimization studies are presented in Volume 2, the appendixes. The contractor is Science Applications, Inc. *EPRI Project Manager: R. K. Winkleblack*

Dynamic Piping Fracture Coupled With System Effects

NP-1640 Annual Report (RP231-1); $5.75

This report describes a study of crack initiation, propagation, and arrest in pressurized piping and the related depressurization response. Crack tip opening angle was used as the dynamic ductile fracture criterion, and two-dimensional stress-intensity factors for long internal and external surface cracks were investigated. The thermal-hydraulic code LEAKER was used to predict depressurization and reaction thrust from axial and circumferential cracking in hot water pipes and to determine the nature and strength of pressure relief waves caused by propagating axial and circumferential cracks. The contractor is the University of Washington. *EPRI Project Manager: H. T. Tang*

Integral Tests of Fast-Neutron Dosimetry Cross Sections

NP-1658 Final Report (RP514-1); $4.50

The fast breeder blanket facility was used for integral tests of dosimetry cross sections. The facility and the reactions for irradiation are described; activity, fission rate, and neutron energy spectra measurements are presented; and measured and calculated reaction rates are compared. The contractor is Purdue University. *EPRI Project Manager: B. R. Sehgal*

Power Shape Monitoring System

NP-1660 Final Report (RP895); Vol. 1, $6.50; Vol. 2, $8.75

Volume 1 provides an overview of the first-generation power shape monitoring system (PSMS) for BWRs, which has been undergoing field testing at the Oyster Creek nuclear plant. The system's functional requirements and its hardware and software are described. The accuracy of the Oyster Creek PSMS is evaluated—specifically, its power prediction capabilities. Volume 2 provides a technical description of the PSMS. Five basic functions are described: a PRIME 400–SIGMA 3 interface, a data acquisition and storage module, a duty cycle approximation module, a fuel reliability evaluation module, and a data display module. The contractor is Nuclear Services Corp. *EPRI Project Managers: A. B. Long, F. E. Gelhaus, S. T. Oldberg, and Burt Zolotar*

Feasibility of Using Gadolinium as a Burnable Poison in PWR Cores

NP-1663 Final Report (RP1453-1); $5.75

The feasibility of substituting Gd_2O_3 admixed with UO_2 for discrete boron-bearing burnable poison elements in PWRs was demonstrated. This involved a three-dimensional study, including depletion, of a first core of modern design. The calculative flow path is described; the development of assembly and core designs is summarized; and the gadolinium and reference designs are compared. The contractor is Science Applications, Inc. *EPRI Project Manager: W. J. Eich*

Review of Natural Circulation Loops in Pressurized Water Reactors and Other Systems

NP-1676-SR Special Report; $3.50

A survey of theoretical and experimental work on single-phase natural circulation loops (thermosyphons) is presented. Analytic and numerical modeling methods for describing steady-state flows, transients, and stability characteristics of various loops are discussed. Nuclear reactor data from various tests and actual operational transients are summarized and compared with theoretical calculations. *EPRI Project Manager: Yoram Zvirin*

Cost-Effectiveness of Countermeasures to IGSCC in BWR Piping

NP-1703 Final Report (RP700-6); $4.50

The economic impact of intergranular stress corrosion cracking (IGSCC) of piping in BWRs is analyzed. The future need for pipe repairs is estimated, and the expected cost of future repairs is calculated for an average plant. Data on IGSCC incidents are compiled, cross-checked, and in some cases traced to the original source for verification. The contractor is Failure Analysis Associates. *EPRI Project Manager: M. J. Fox*

Assessment of Maintainability of LMFBR Designs

NP-1714 Final Report (RP1704-1); Vol. 1, $15.25; Vol. 2, $11.25

Volume 1 presents an evaluation of the maintainability of representative components of the pool-type and loop-type plant designs developed in recent prototype large breeder reactor studies. The plant designs were reviewed from the standpoint of practicality of component maintenance; for the components whose removal and replacement were evaluated, maintenance procedures were developed. Volume 2 presents appendixes on radiation exposure, general features of the sodium components maintenance facility, maintenance procedures, and experience with sodium-cooled breeder reactors. The contractor is ETA Engineering, Inc. *EPRI Project Manager: Joseph Matte III*

Rhodium In-Core Detector Sensitivity Depletion, Cycles 2–4

NP-1715 Interim Report (RP1397-1); $2.75

This report describes an effort to empirically define the sensitivity depletion characteristics (over the operating lifetime) of rhodium self-powered neutron detectors. Two detectors have been positioned inside the reactor core of the Oconee-2 PWR for measurement since July 1976. An analysis of rhodium depletion data from fuel cycles 2, 3, and 4 is presented. The contractor is Babcock & Wilcox Co. *EPRI Project Manager: H. G. Shugars*

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