The Greenhouse Effect and Global Warming

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Cover: The buildup of CO_2 and certain trace gases in the atmosphere is blocking the natural escape of much of the earth's heat from our environment. Experts believe that the resultant warming trend could have profound implications for the earth's climate in as few as 50 years.

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The Scientific Unknowns of CO_2

Malès

Coming to appropriate decisions on complex environmental issues is extremely difficult, a fact that is often ignored by advocates of one or another policy prescription. Usually, it is only with hindsight that an action appears to be undeniably the preferred policy option. Only 50 years ago the heavy particulate and gaseous loadings that make up urban smog were deemed a sign of industrial progress and a necessary concomitant cost of economic growth; in the United States, these levels of urban pollution are now perceived to be unacceptable. Although opinions may differ on the appropriate degree and method of restriction, few would argue that the emissions limitations imposed by state and federal laws and regulations are undesirable.

Unfortunately, the benefit of hindsight is not available for environmental issues we are studying today. The so-called greenhouse effect—the buildup of CO_2 in our atmosphere and the consequent possible effect on climate—is a classic example of the difficulty of dealing with complex scientific unknowns.

This issue involves tough basic questions: what happens to the CO_2 that is emitted from our industrial combustion processes? what are the other sources of CO_2? what are the sinks? Even when we become relatively knowledgeable about these questions, a whole series of others loom ominously: what will be the effect of various levels of CO_2 in the atmosphere? how do other greenhouse gases affect the climate? what are the possible feedback loops from initial warming effects? As with all scientific issues, research will never bring absolute certainty, but well-designed research can advance the understanding and reduce the degree of uncertainty for each of these phenomena.

The eventual decision on whether to limit emissions of CO_2 and the other greenhouse gases and how to effect such limits will be a political one—a decision that balances risks against costs, that takes into account public values. Yet such a decision will be easier to make and will be better designed if we know more about the science of the issue. EPRI has the role of developing such scientific and technical understanding for the electric utility industry.

Fortunately, DOE has a large ongoing research program addressing many of these scientific questions. EPRI can share in these results and build its much more modest research agenda as a complement to DOE's research. Similarly, other federal agencies are looking at issues related to CO_2. By coordinating with these agencies, EPRI can help utilities keep up to date on a field in which they may be called upon to take policy positions.

René H. Malès, Vice President
Energy Analysis and Environment Division

Authors and Articles

Hakkarinen Hansen Spencer Dolbec Dohner Gluckman Welty Robinson

The Greenhouse Effect: Earth's Climate in Transition (page 4) examines the myriad mechanisms by which carbon is exchanged between plants, oceans, and the atmosphere, and the potential outcomes. Written by Michael Shepard, *Journal* feature writer, who received principal technical guidance from three EPRI research managers.

Charles Hakkarinen is technical manager for environmental data analysis in the Energy Analysis and Environment Division. Formerly an assistant to the division director, he has been with EPRI since 1974, when he was still completing work on his PhD in environmental science and engineering at the University of California at Los Angeles.

Alan Hansen, also in the EAE Division, is a project manager in the Environmental Chemistry and Physics Program. He came to EPRI in March 1985 after eight years with Environmental Research & Technology, Inc., where he was manager of environmental chemistry. He was previously an environmental analyst and a research chemist with the Environmental Protection Agency, the University of California (Riverside) Air Pollution Research Center, and SRI International. Hansen earned a PhD in chemistry at the University of California (Irvine).

Dwain Spencer is an EPRI vice president and director of the Advanced Power Systems Division. Before he joined the Institute in 1974, he was with the Jet Propulsion Laboratory of the California Institute of Technology for 16 years, part of that time in studies of planetary atmospheres in which space vehicles would travel. Spencer has a BS in chemical engineering from the University of Notre Dame and an MS in engineering from Purdue University. ■

Evolution in Combustion Turbines (page 16) reviews the thinking and the R&D that are adapting an already-modular prime mover for intermediate and baseload use. Written by Michael Shepard, *Journal* feature writer, aided by members of EPRI's Advanced Power Systems Division.

Albert Dolbec has managed his division's research in power machinery since 1978. He came to EPRI a year earlier after nearly 26 years with General Electric Co., where he became manager of design engineering for gas turbine and combined-cycle plant controls. He is an electrical engineering graduate of Manhattan College.

Clark Dohner, a project manager in Dolbec's program, has been with EPRI since 1982, guiding R&D in gas turbines. He formerly was with General Electric for 20 years, the last 10 in the gas turbine division. Dohner has BS and MS degrees in mechanical engineering from Johns Hopkins University and the University of Pittsburgh, respectively.

Michael Gluckman heads the Engineering and Economics Evaluation Program. He was named to the position in 1980 after five years as project manager in gasification system research. Between 1971 and 1975 he was an associate professor of chemical engineering at City College of the City University of New York, where he earned his PhD. ■

Remote Scanning of Low-Level Waste (page 22) presents two new, fast, safe, and thorough ways to measure certain radioisotopic contents of waste material. Written by Taylor Moore, the *Journal's* senior feature writer, with the cooperation of two research managers in the Nuclear Power Division.

Charles Welty, a project manager in low-level waste and coolant technology research, has also managed EPRI research for the utility Steam Generator Owners Group. He came to EPRI in 1978 after three years as production manager and manager of the Dillingham Corp. shipyard in Honolulu. A graduate of the U.S. Naval Academy, Welty was an officer in the navy's nuclear submarine force for nine years.

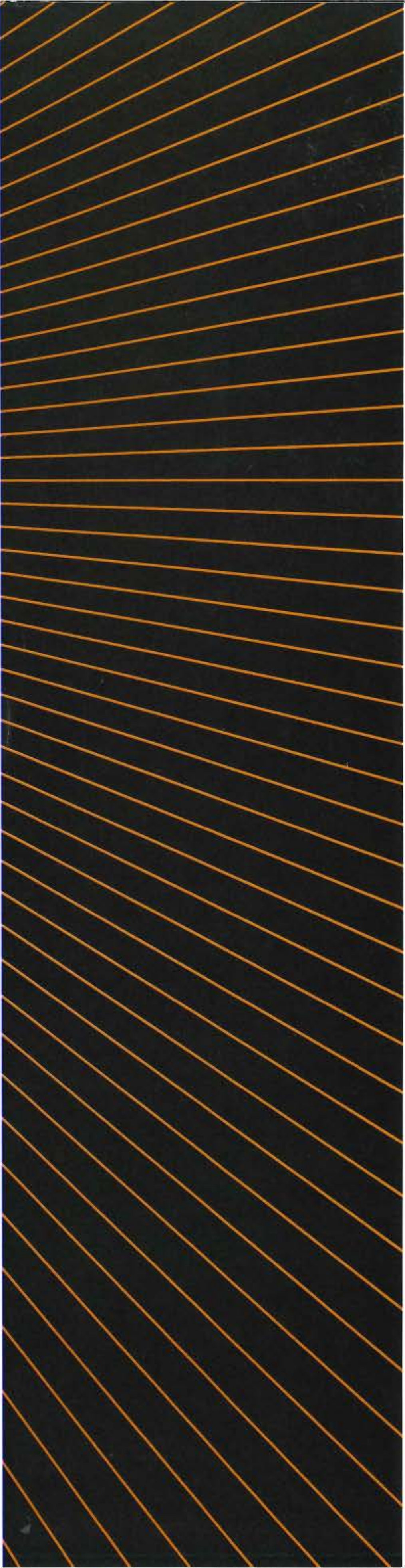
Patricia Robinson, also a project manager for low-level waste research, has been with EPRI since August 1985. She was formerly a research engineer at Battelle, Pacific Northwest Laboratories for two years. Between 1977 and 1983 Robinson worked for two companies providing reactor operation and waste transportation services at the federal government's Hanford site. She has a BS in chemical engineering from the University of Nevada (Reno). ■

Herbert Woodson: Encouraging Exploration in Research (page 28) introduces a Texas engineering professor and member of EPRI's Advisory Council who has a well-developed loyalty to R&D. Written by Ralph Whitaker, the *Journal's* feature editor, from an interview with Woodson. ■

THE GREENHOUSE EFFECT

Earth's Climate in Transition

Theories of global warming are gaining broad acceptance in the scientific community, with many experts predicting significant change within 50 years. The sweeping consequences of accumulating greenhouse gases in the atmosphere may turn out to be the greatest environmental problem of modern times.



Climate, that amalgam of nature's moods, shapes the character of places and human activity as powerfully as any other force. It influences where we live and how we like it. Climate allows corn to flourish in Iowa and causes crops to fail in Africa. It makes Siberia harsh, Tahiti gentle, and lends distinct personalities to every other place on the globe.

Until recently, we took climate for granted and accepted that it would stay largely the same, at least in our lifetimes and those of our children. Evidence is mounting, however, that by burning fossil fuels, leveling tropical forests, and engaging in a number of other activities, humans are releasing gases to the atmosphere that could trap enough heat to raise the temperature of the earth's surface by a few degrees Celsius. No such increase has yet been detected. If and when it comes, however, even a few degrees' rise would change the climate of many regions. Some places may become sunnier, others wetter. Today's deserts may bloom and some farming regions may wither. The timing of frosts that bound growing seasons will change, as will the frequency of midsummer heat waves. Sea level could rise from several inches to a few feet, affecting coastal regions in numerous ways. Some areas will change very little. Others may change a lot.

The first signal of these potential changes came from measurements of the steady rise in atmospheric carbon dioxide (CO_2) made by Charles Keeling of the Scripps Institution of Oceanography. His readings from the observatory at Mauna Loa, Hawaii, show that CO_2 has climbed from a concentration of 315 parts per million (ppm) in 1958 to 345 ppm today. A National Academy of Sciences report released in 1983 projected that within 50 to 100 years the level of CO_2 is likely to rise to 600 ppm. Because CO_2 acts as a thermal blanket in the air, explains the NAS report, this doubling of gas concentration could raise average global temperature by 1.5–4.5°C (2.7–8.1°F). A 1.5°C warming within a century would produce the warmest climate seen on earth in 6000 years. A 4.5°C rise would place the world in a temperature regime last experienced in the Mesozoic era—the age of dinosaurs.

One of the key uncertainties in projecting temperature change centers on the question of how much of the CO_2 released to the atmosphere will remain there. We know from the measured increase in atmospheric CO_2 that 2.5 billion tons of carbon per year, an amount equal to half the annual emissions from fossil fuel combustion, accumulates in the air. The rest, scientists believe, must be going into terrestrial plants and into the oceans. Plants absorb CO_2 through photosynthesis and release it through respiration, storing some of the carbon that they metabolize in their leaves, stems, and roots. CO_2 enters the ocean by dissolving out of the air into the surface waters. Some of the carbon stays dissolved as CO_2 in the surface water, some is carried into the deep ocean by currents or precipitates into solid particles that fall to the bottom, and some bubbles back out to the atmosphere, much like gas escaping from a bottle of club soda.

Scientists do not yet agree on how the CO_2 that leaves the atmosphere is apportioned among the plants and oceans, nor do they know how much more CO_2 these reservoirs can absorb or how long they will hold it. Without a clear understanding of the pools and flows of carbon in the earth-water-air system, it is impossible to precisely estimate future atmospheric CO_2 levels. Knowing how much CO_2 will be in the atmosphere in the future only gets us to square one. From there we have to explore the gas's effects on temperature and ultimately on climate.

Temperature and climate: A question of balance

The earth's climate is driven in part by temperature, and temperature is a function of the balance between energy coming in from the sun and energy radiating back to space. This balance is influenced by the atmosphere, which is transparent to visible light (between 0.4 and 0.7 μm) but is opaque to certain wavelengths of infrared, or heat, radiation (longer than 0.7 μm).

Slightly more than half the light entering the atmosphere is absorbed by clouds and particles or reflected back to space. The remainder is absorbed at the surface, warming the oceans and land. The warmed surfaces then reradiate this energy in the form of heat. Naturally occurring water vapor and CO_2 in the atmosphere absorb certain wavelengths of this heat and radiate some of it back to earth. This phenomenon is referred to as the greenhouse effect, because it is analogous to the trapping of heat inside a glass enclosure. The air traps enough heat to keep the earth's surface about 30°C (54°F) warmer, on average, than it would be without an atmosphere.

Because naturally occurring gases in the atmosphere do not absorb all infrared wavelengths, some of the heat radiated by the land and sea escapes back to space. Most of this escaping heat is radiation with wavelengths between 7 and 12 μm, a band in which water vapor and CO_2 absorb weakly. Thus the atmosphere (even with high CO_2 levels) is largely transparent to infrared radiation in this range. This atmospheric window is critical to climate. Without the window, more heat would be trapped in the lower atmosphere, the earth would be warmer, and the patterns of atmospheric circulation that shape climate would be altered.

Factoring in trace gases

Ralph Cicerone of the National Center for Atmospheric Research (NCAR) and three colleagues recently published the results of an extensive study on the rate at which greenhouse gases other than CO_2 are accumulating in the atmosphere and the effects these gases may have on climate. The gases of concern are present in minute but rising amounts, they remain in the atmosphere for many years, and they are powerful absorbers of infrared radiation between 7 and 12 μm.

The ringleaders of this group are methane, ozone, nitrous oxide, and several chlorofluorocarbons (Freons). The chlorofluorocarbons arise exclusively from human activity. Although banned in the United States as aerosol propellants, these compounds are still used throughout the world as refrigerants and solvents and in numerous industrial processes.

The sources of other greenhouse gases are not as clearly understood. Methane, for instance, has been rising at 1%/yr over the past three decades. Cicerone believes that much of the increase in this gas can be traced to mineral exploration and mining, rapidly growing populations of cattle and termites, which excrete methane, and decomposition of organic matter in rice paddies that for the first time are bearing two and three crops annually with the expansion of modern irrigation systems. He traces the rise in nitrous oxide in part to the use of nitrogen fertilizer in agriculture.

Cicerone and his coworkers calculate that the combined effect of these gases is already 60% as great as the effect from current CO_2 levels and within 50 years will equal or exceed CO_2's influence. This additional effect could cause global temperature to rise faster than most models now predict.

Not all scientists agree with the magnitude of the prevailing warming predictions, however, and much of this disagreement hinges on estimates of the size and direction of various feedbacks that may occur in response to the initial perturbation of the climate. Some responses, called negative feedback, will have a cooling effect that will dampen the warming trend. Positive feedback, on the other hand, will reinforce the initial warming.

Understanding feedbacks

One of the key feedback uncertainties concerns clouds. "If the atmosphere warms," says Richard Somerville, a theoretical meteorologist and head of the climate research group at Scripps, "more water will evaporate into the air, changing the area, height, water content, and reflectivity of clouds." Plugging plausible numbers for changes in cloud reflectivity into a climate model, Somerville found that the range of projections for global warming could be either doubled or halved. He hastens to add that these results do not prove the models wrong. "Rather, they point to questions of potential importance that we have to understand better before we can rely with confidence on our model results."

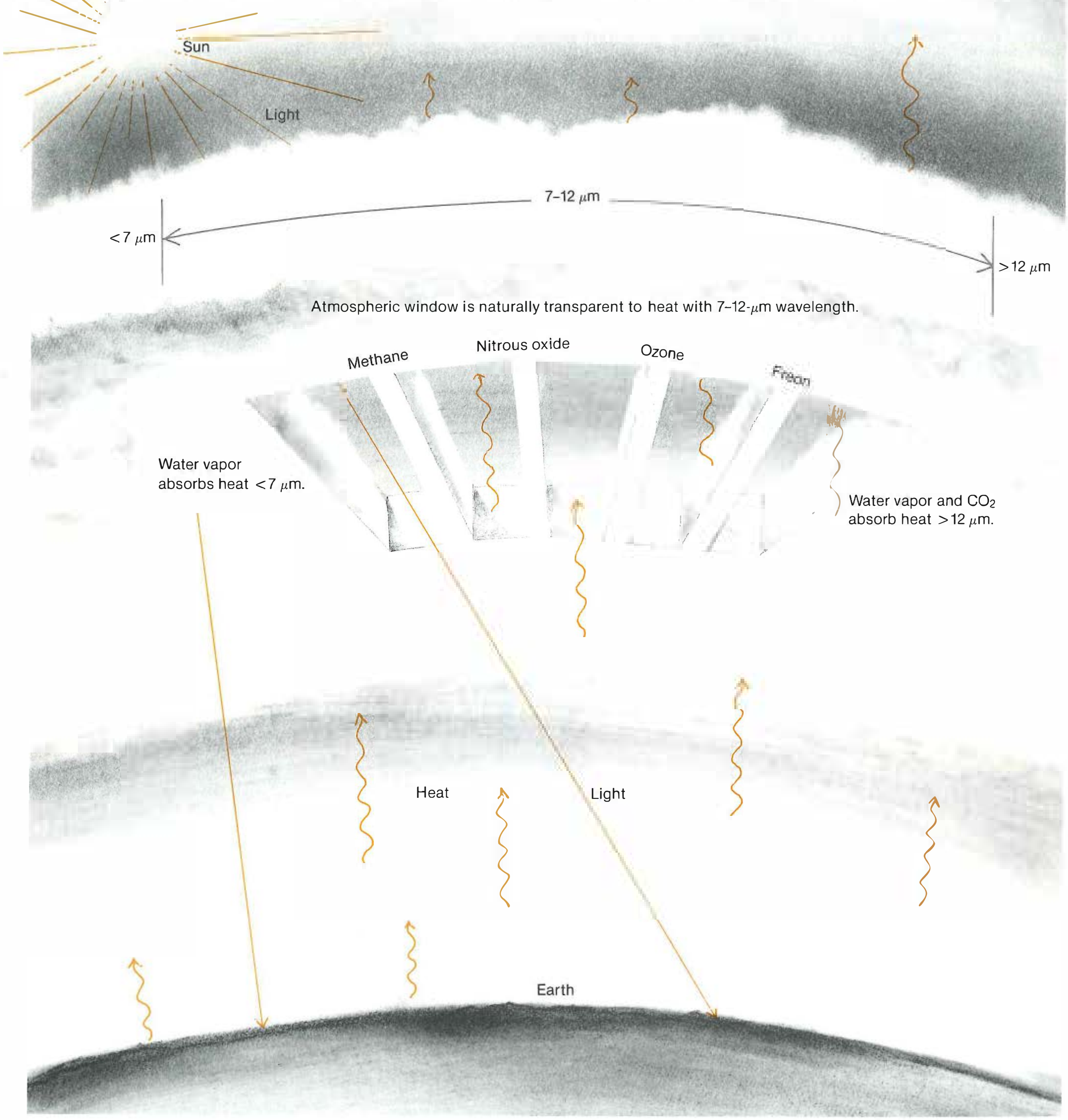
Another feedback uncertainty involves the response of plants to rising CO_2 levels. The Carbon Dioxide Research Office of the U.S. Department of Energy (DOE), the government's lead agency in the study of CO_2 and climate, devotes a considerable portion of its $13 million annual budget to investigating the effects of rising CO_2 on vegetation. In a series of controlled studies, agricultural crops grew 30–90% faster in a high-CO_2 environment, pulling more carbon out of the atmosphere and storing it in plant tissues. Moreover, water-use efficiency rose significantly in several of the crops. Some scientists point to such findings with hope that an atmosphere richer in CO_2 could lead to higher food yields in the future and that enhanced plant growth could slow the rise in CO_2 and global temperature.

Although crops may respond positively to higher CO_2 when other conditions are controlled, very little research has been conducted on the response of the unmanaged forests, grasslands, and tundra that cover much of the earth.

Walter Oechel, director of the Systems Ecology Research Group for the California State University at San Diego, conducted one of the few studies yet performed in a native ecosystem to

Blocking the Atmospheric Window

The so-called greenhouse effect is caused by atmospheric gases that absorb certain wavelengths of heat that would otherwise radiate out to space. Carbon dioxide is not the only greenhouse gas whose concentration is rising as a consequence of human activity. Methane, nitrous oxide, ozone, Freon, and several other gases are of particular concern because they remain in the air for many years and are potent absorbers of heat within the wavelength band (7–12 μm) through which much of the earth's heat escapes the atmosphere. By blocking parts of this atmospheric window, very small amounts of these gases can exert a warming effect as great as that caused by the much more abundant CO_2.



measure long-term plant responses to elevated CO_2. Oechel exposed several species of tundra plants to varying levels of CO_2 and temperature for three years. He found that the response in native species was less than that found for many agricultural crops. He also found significant variability in the responses of the native species examined. Some species exposed to elevated CO_2 and higher temperature grew faster and stored more carbon, but other species did not. "Overall," explains Oechel, "arctic tundra exposed to higher CO_2 and ambient temperatures stored more carbon than tundra under current CO_2 levels, but not as much as predicted."

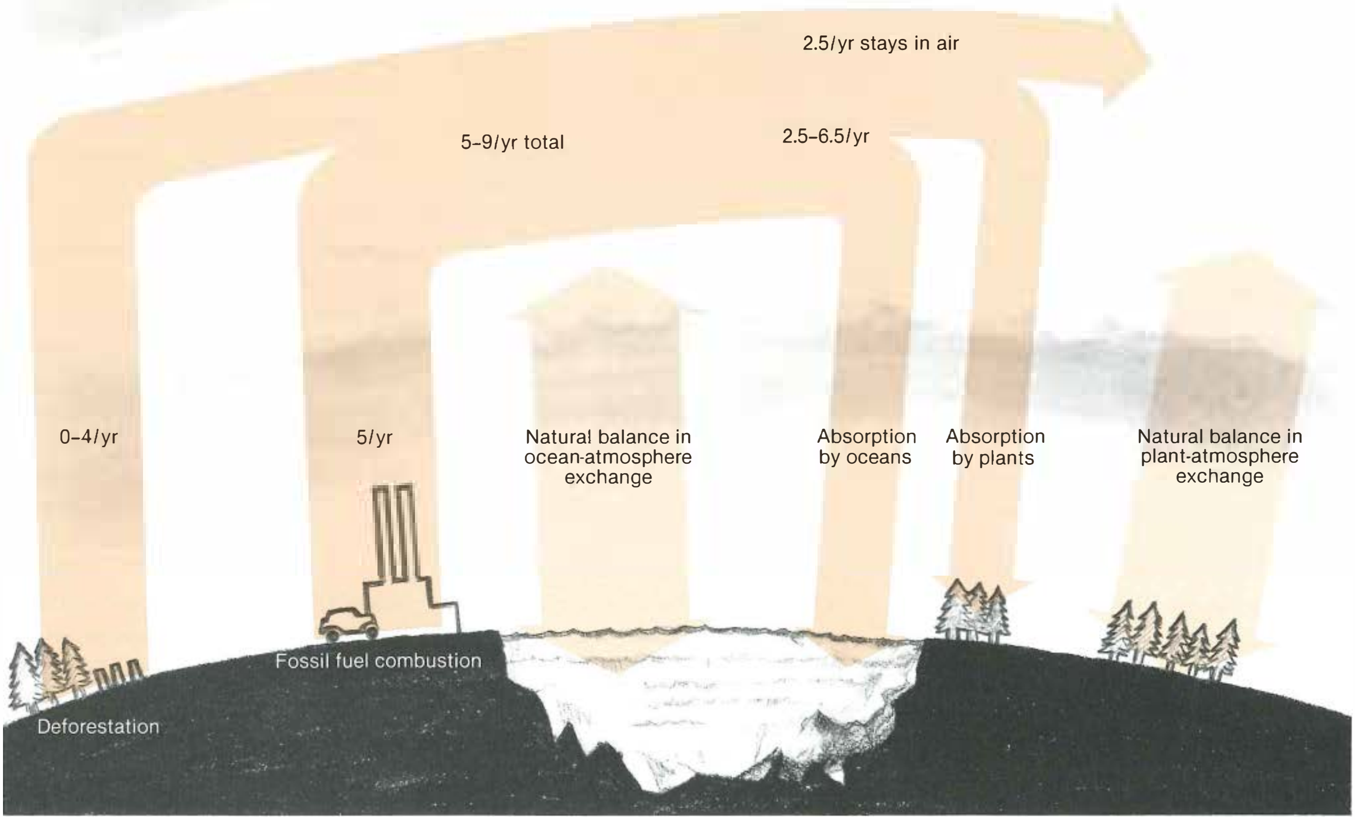
Oechel believes that more research is needed to determine the overall response of the tundra to rising CO_2. Moreover, he stresses that although much of what we learn in the arctic communities will carry over to the boreal forests and other ecosystems, additional research is necessary to understand the responses of those other communities.

George Woodwell, director of the Woods Hole Research Center, agrees that we need more research in the area of plant response. "There is no question that under experimental conditions when water and nutrients are not limiting, you can show that an increase in CO_2 can increase the rate of carbon fixation. But there is no evidence that this is occurring in nature. In fact, the higher rates of organic matter decay that would occur in the soils of the middle and high latitudes due to climate warming, in combination with the rapid deforestation now under way in the tropics, will release large amounts of CO_2 to the atmosphere. These effects will be counterbalanced to some degree by increased photosynthesis and longer growing seasons in some areas, but the net effect will be that plants will add more CO_2 to the atmosphere than they absorb."

The NAS report acknowledges the

Carbon Cycle Is Key to Temperature Change

Without man's influence, the flows of carbon (given in units of 10^9 t) between the air, plants, and ocean would be roughly balanced. Fossil fuel combustion adds about 5×10^9 t/yr of carbon to the atmosphere, about half of which remains in the atmosphere as rising CO_2 levels. The rest is absorbed by plants and oceans, but scientists disagree on how much goes to each reservoir (stocks in units of 10^9 t). Some believe that plants are growing faster in the CO_2-enriched atmosphere and are absorbing up to half the carbon that does not remain in the air. Others believe deforestation is outstripping any enhanced growth that might be occurring, causing plants to be a net source, rather than a sink for CO_2. Scientists must resolve this debate before they can confidently predict how CO_2 levels will rise in the future.



importance of this question, explaining that if deforestation has caused terrestrial ecosystems to be a net source of CO_2 in recent years, the oceans must be taking up far more CO_2 than current models suggest. If oceans are better at absorbing CO_2 than scientists currently believe them to be, the study concludes, "the CO_2 increase will probably occur more slowly than it otherwise would."

Perhaps of greater significance than the feedback involving terrestrial plants and soils are the immense and very complex ocean-atmosphere interactions. The oceans contain 55 times as much carbon as does the atmosphere and 20 times as much as do land plants. Thus, small changes in the oceans' capacity to store carbon can dramatically alter the atmospheric concentration.

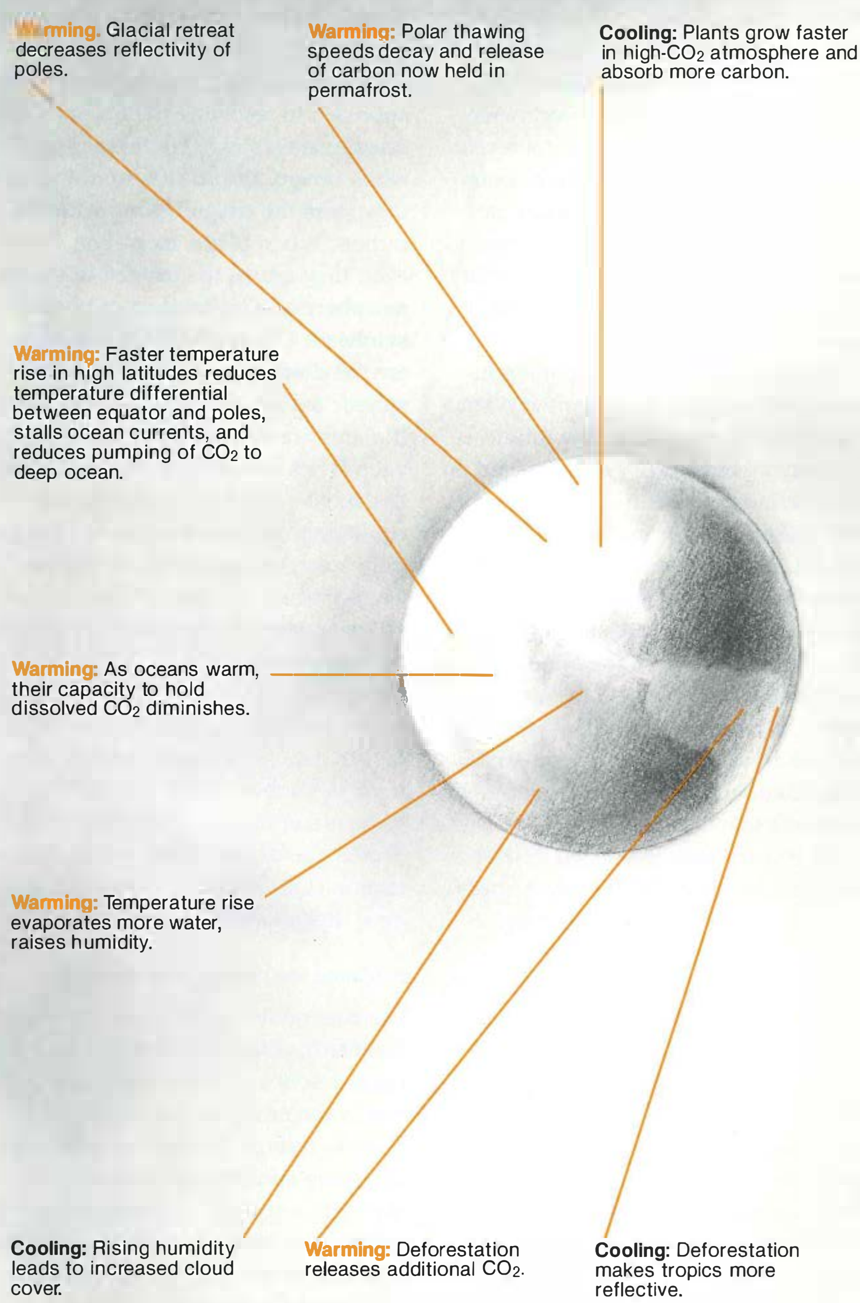
In most areas, atmospheric CO_2 mixes only with the top 100 m or so of sea water and is prevented from cycling downward by thermal gradients that separate the surface layer from deeper waters. However, researchers say that the only long-term way for the oceans to buffer the rise in atmospheric CO_2 is to pump the carbon into the deep ocean, either as dissolved gas or as solid carbonate particles that settle in the sediments at the ocean bottom. Scientists believe that CO_2 is drawn into the deep ocean through currents in a few key locations like the North Atlantic, where cold surface waters are known to sink to the bottom. Some researchers speculate that a global warming could cause the oceans' currents to become more sluggish, reducing their absorption and storage of carbon and exacerbating the greenhouse effect.

A needle in the haystack

Making the measurements needed to determine key parameters like uptake, storage, and release of CO_2 by oceans and plants is akin to burrowing through a haystack in search of one slender needle. Terrestrial ecosystems and oceans are huge, diverse reser-

Potential Feedbacks to Warming

Feedback related to an initial greenhouse warming will have important effects on long-term temperature change. Some responses (positive feedback) are expected to exacerbate the warming. Others (negative feedback) will probably have a cooling effect. The net result remains uncertain, although current estimates are for a 1.5–4.5°C temperature rise within a century.



voirs, and scientists are trying to measure minute changes in their composition. Compounding the difficulty, these reservoirs are not at all uniform. Trees absorb and store carbon very differently than do grasslands and tundra, and oceans vary widely in temperature, depth, water chemistry, and circulation. This heterogeneity means that measurements from a few locations only hint at what is happening worldwide. One researcher commented at a recent conference that it would take 10 years and hundreds of people in boats gathering water samples from all around the world to yield even a fuzzy picture of oceanic absorption, storage, and release of carbon.

Figuring out what is happening in plant communities is similarly challenging. Oechel's research in the tundra is the only in situ study yet conducted on ecosystem response to elevated CO_2, and even this work involves controlled conditions. For the most part, however, researchers are trying to deduce what is happening in the plants and oceans by measuring changes in the atmosphere more accurately. Because the atmosphere is better mixed and more uniform than the oceans and terrestrial plant communities, it is an easier reservoir to monitor.

"If you are only interested in average, long-term, global trends in atmospheric concentrations, one or two monitoring sites are sufficient," explains Pieter Tans, who directs the CO_2 monitoring program for the National Oceanic and Atmospheric Administration (NOAA). "But if you want to determine where the main sources and sinks are, you have to measure local gradients and see how they change with the seasons. This requires many measurements, over time, from lots of sites."

NOAA operates a network of 26 remote monitoring stations from Point Barrow, Alaska, to the South Pole. "Precision in gathering and analyzing samples is critical," says Tans. Technicians are instructed to take samples only on windy days when breezes are blowing from the sea so as to avoid local effects from land plants. Roughly 6000 samples a year are sent to NOAA in pressurized steel containers lined on the inside with gold or other inert substances that will not react with the sample gas.

Tans is pursuing an ingenious new approach to resolving the question of ocean-plant uptake. He reasons that when oceans absorb CO_2 from the air, they store the oxygen along with the carbon. When plants fix carbon, however, they return the oxygen to the atmosphere as a by-product of photosynthesis. Consequently, if the oceans are the dominant sink for CO_2, atmospheric oxygen levels should be falling. If plants are a major sink, however, oxygen levels should stay the same. Tans has spent several years developing equipment to measure minute changes in the oxygen content of air. He believes that his equipment, which uses an argon laser, fiber optics, and spectral analysis of gas samples, will soon be ready to be put into service.

The whole point behind these exhaustive monitoring efforts is to determine the rate at which greenhouse gases accumulate in the atmosphere. This is one of the critical pieces of information climate modelers need to study how climate may change.

Modeling the climate response

Climate models are nothing more than hundreds of linked mathematical equations describing how various phenomena in the environment cause conditions to change throughout the system. Incoming sunlight, for instance, heats the earth's surface, particularly near the equator, causing warmed air in the low latitudes to rise and circulate toward the poles. The earth's rotation interacts with these currents to cause the trade winds. Water evaporating off the oceans circulates in the atmosphere and falls to the surface as precipitation. The tilt of the earth's axis causes different amounts of energy to flow into the northern and southern hemispheres and leads to the annual cycles we call seasons. These and related processes that determine climate are reduced to numbers and symbols in sophisticated computer programs known as general circulation models. These are the tools climatologists use to study the climate and to predict how it will change in the future.

Climatologists check the accuracy of their models by running them forward and backward. Years can be reconstructed in a few days of computer time. If the models can reconstruct known present or past conditions, modelers feel confident in using them to project future climates.

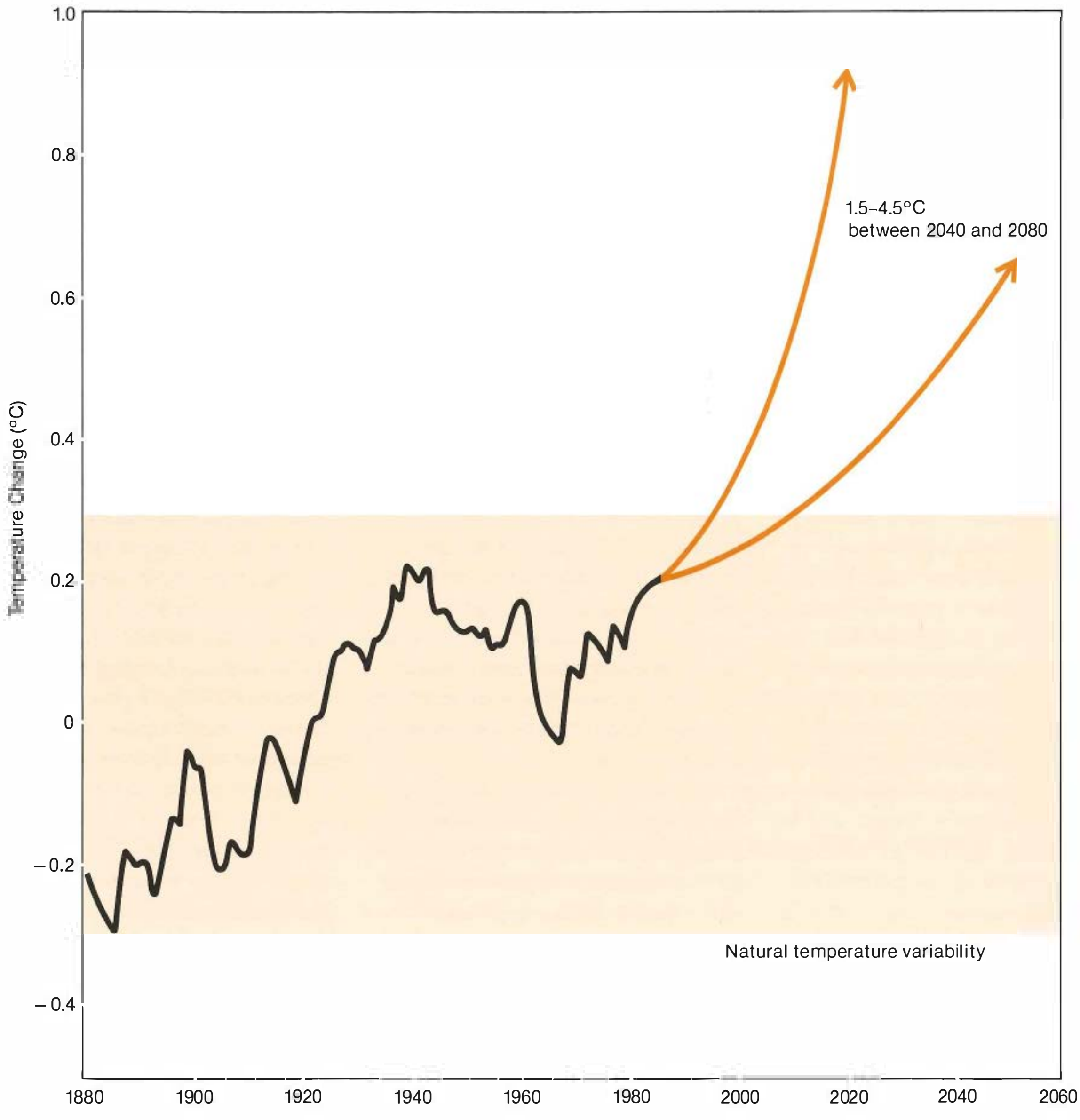
To determine if their models successfully recreate the past, climatologists have long been seeking reliable estimates of the CO_2 levels that existed in the atmosphere before the industrial revolution, when fossil fuels were first burned on a large scale. Several methods, including analysis of air trapped centuries ago in polar ice caps and carbon fixed in tree rings and slow-growing ocean sponges, have been used to unravel this mystery. The emerging consensus is that the CO_2 concentration stood at roughly 280 ppm in the eighteenth century, a level 65 ppm below today's concentration.

Most of the modeling studies of CO_2-induced climate change have been run on a few general circulation models (GCMs) in the United States. The Geophysical Fluid Dynamics Laboratory model at Princeton University predicts a global warming of 2°C for a doubling of CO_2, although the Goddard Institute for Space Studies (GISS) and NCAR models yield about a 4°C (7.2°F) increase.

Climatologists are anxiously poring over temperature measurements year by year to see if a greenhouse signal is emerging from the noise of natural temperature fluctuations. Nearly all

Observed and Projected Temperature

The earth's average temperature rose about 0.5°C (0.9°F) over the past century, with a 0.2°C (0.36°F) cooling observed (black) between 1940 and 1965. Although the temperature rise is not inconsistent with predicted effects of CO_2 and other greenhouse gases, the fluctuations are still within the normal range of temperature variation. Many climatologists expect a CO_2 signal to rise above the background noise in the 1990s. Projections (color) for temperature increases caused by a doubling of CO_2 are 1.5–4.5°C (2.7–8.1°F) within 50 to 100 years. These projections do not consider the influence of other greenhouse gases, which could speed the warming.



EPRI STUDIES GREENHOUSE EFFECT

EPRI has sponsored a number of research efforts in the area of greenhouse gases and climate change. These projects generally focus on one of two areas: the scientific aspects of the problem and the analytic and decision-making techniques for evaluating and responding to CO_2–induced changes.

Radian Corp. completed a study for EPRI's Coal Combustion Systems Division in 1980, assessing the scientific uncertainties of the issue, projecting CO_2 emissions worldwide, and evaluating the prospects for CO_2 emissions control and the social and economic implications of a global warming. Noting that U.S. utilities produce less than 10% of the global CO_2 emissions from fossil fuel combustion, the report concludes that an international effort to reduce fossil fuel use would be required to curb CO_2 buildup.

Half a dozen chemical and physical processes have been proposed for capturing the CO_2 from fossil-fuel-fired power plant emissions. Radian concluded that although some are technologically feasible, none are economically practical. They would add several hundred dollars per kilowatt to plant capital costs, would add an undetermined amount in operating expenses, and would consume half or more of the plant's energy output. Consequently, no cost-effective means has yet been found for storing the captured carbon over long periods to keep it from returning to the atmosphere.

EPRI's Energy Analysis and Environment (EAE) division has sponsored about half a dozen studies in the CO_2 area since 1978. René Malès, vice president and EAE division director, explains, "This issue is a classic environmental risk management problem. There are large uncertainties in possible outcomes, significant environmental consequences under certain conditions, and high costs for changing these conditions. The role we play is to get clearer scientific insights in order to be able to more accurately evaluate the risks involved."

Beginning in 1983, EAE sponsored a study with Scripps to resolve uncertainties concerning global sources and sinks of CO_2. Although the research team refined its atmospheric and oceanic models in this effort, many details of the carbon cycle remain elusive. Consequently, a proposal to continue this work, incorporating satellite imagery and enhanced three-dimensional modeling of ocean circulation, is now under review.

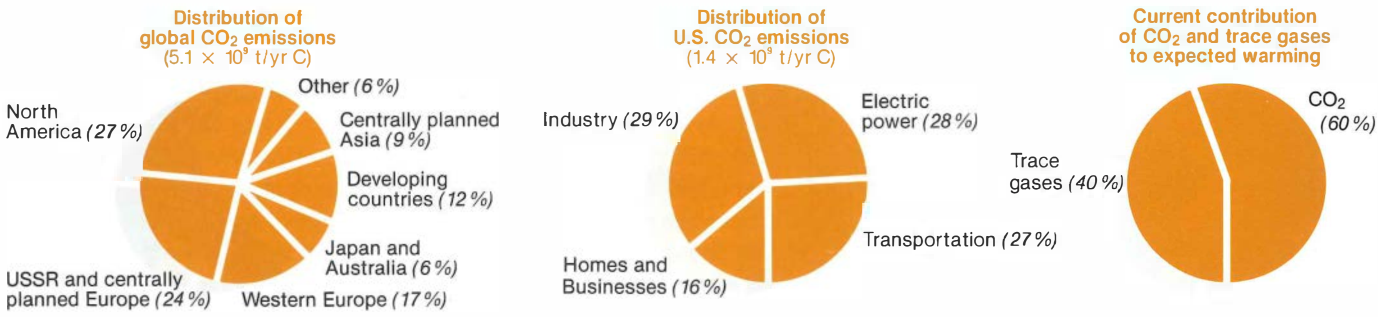
Another study, conducted for EPRI by the Oak Ridge National Laboratory, assessed how the rates of CO_2 accumulation would change under different electricity generation scenarios and then explored the potential effects on climate, agriculture, the economy, and ecosystems.

One recently completed study produced a preliminary greenhouse effect decision framework to help EPRI, utilities, and government research managers plan research on CO_2 and trace gases in a manner that focuses on the most important questions and yields the highest payoff. In another decision-related contract (cosponsored by EPRI, EPA, EEI, and NYSERDA), ICF, Inc., is exploring the potential effects of climate change on electric utilities. Using Florida Power & Light Co. as a case study, ICF is gathering information on the utility's demand and generation plans for the next 30 years. ICF will then analyze how a number of major factors may change with variations in temperature and rainfall, including the demand patterns of major customers, the utility's operating characteristics, new capacity requirements, demand management, and various financial issues. Once the FP&L analysis is complete, the methodology will be evaluated, changed as necessary, and then applied in two additional utility case studies. The project is scheduled for completion in early 1987.

EPRI's Advanced Power Systems Division has also supported a modest effort in the CO_2 area. In May 1985 APS sponsored a five-day conference at Lake Arrowhead, California, at which 40 leading scientists discussed their investigations of CO_2 transfer between the atmosphere, ocean, and terrestrial plants. The conference was organized by Scripps as part of a contract with the APS division to improve its models of ocean-atmosphere exchanges of CO_2. Topics ranged from the latest techniques for estimating preindustrial CO_2 levels, through ecosystem responses to elevated CO_2, to new developments in oceanic and atmospheric modeling. As Dwain Spencer, EPRI vice president and APS division director, explains, "We believe that the increases of carbon dioxide in the earth's atmosphere must be considered in planning a long-term research strategy for the power industry. At this time we are attempting to understand the key sources and sinks for CO_2 and the important feedback mechanisms that may either ameliorate or exacerbate the problem in the twenty-first century." □

A Global Issue

1980 figures on the distribution of CO_2 emissions from fossil fuels in the United States and from around the world demonstrate the international nature of the issue. The United States produces about one-quarter of global CO_2 emissions, and electric utilities produce about one-quarter of U.S. emissions, or less than 8% of the global total. Trace greenhouse gases are increasing rapidly and are expected to match CO_2's contribution to global warming within 50 years. These trace gases are also produced throughout the world, adding to the international complexity of the greenhouse issue.



agree that no definite signal has yet appeared, but many expect to see it within a decade.

One of the principal limitations in climate models is their ability to predict regional changes accurately—how will conditions change where people live, work, and farm? Will Iowa still be a good place to raise corn? Will the Gulf Stream stall and make Britain much colder? Will the drought-stricken areas of Africa get more rain? Some of the most sophisticated models are beginning to produce regional predictions, but the jury is still out on their accuracy. For now, most researchers shy away from regional prognoses, but they do feel confident about their projections of global average change.

So what's a few degrees?

Although an average warming of a few degrees does not sound like much, it could create dramatic changes in climatic extremes. The frequency of midsummer heat waves in certain locations, for example, could rise significantly. This could have important effects on, among other things, agriculture, energy consumption, and human comfort. NCAR climate specialist Steven Schneider and two colleagues found that the frequency of periods of five days or more exceeding 35°C (95°F) in the Corn Belt would grow threefold in the event of an average global warming of 1.7°C (3°F). Such conditions at critical stages in the growing season are known to harm corn and lead to reduced yields. A similar study conducted by James Hansen, director of GISS, and his student Paul Ashcraft concluded that the number of days warmer than 32°C (90°F) and 38°C (100°F) and nights above 27°C (80°F) would rise dramatically in eight major American cities as a result of doubled CO_2. The effect on utility cooling loads could be substantial.

Changes in the timing and amount of precipitation will almost certainly occur if the climate warms, affecting agriculture and hydroelectric resources, among other things. Soil moisture, which is critical during planting and early growth periods, will change. Rising CO_2 levels may enhance growth rates and water-use efficiency in some crops in certain areas. Some regions will probably become more productive, while other places may become less suited to agriculture. The North American grain belt, according to at least one climate model, will shift northward into Canada as the warming produces drier, hotter conditions in the American Midwest.

Of all the effects of a global warming, none has captured more attention than the prospect of rising sea levels from the melting of land-based glaciers and volume expansion of ocean water as it warms. Estimates of the rise range from several inches to a dozen or more feet by the year 2100, although the prevailing weight of opinion calls for an increase of about a foot and a half. The most dramatic scenario is that the West Antarctic ice sheet, which rests on land that is below sea level, could slide into the sea if the buttress of floating ice separating it from the ocean were to melt. This would raise the average sea level 15–20 ft (4.6–6.1 m).

Even a 1 ft (0.3-m) rise would have major effects on the erosion of coastlines, salt water intrusion into the water supply of coastal communities, flooding of marshes, and the inland extent of surges from large storms.

What can be done?

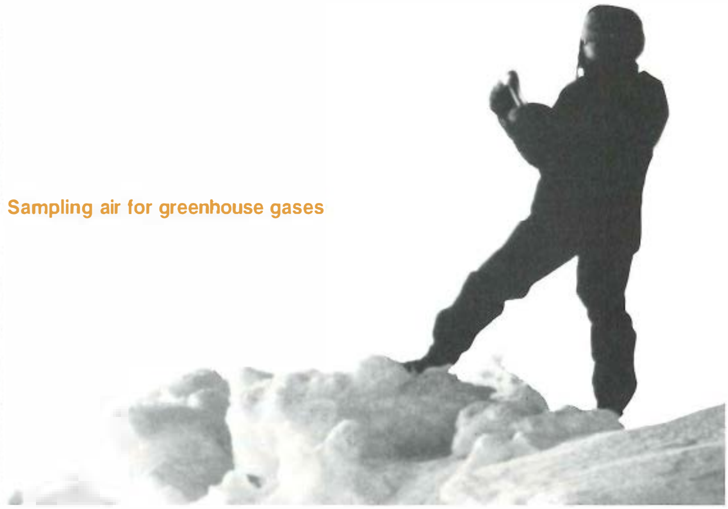
Many observers are beginning to discuss responses to potential climate change. Three basic views characterize the debate: we do not know enough yet about the fundamental processes to respond effectively; we should apply what we do know now to mitigate the changes; we should accept that climate change is inevitable and start immediately to adapt.

Frederick Koomanoff, who directs DOE's CO_2 research, holds firmly to the view that we have to conduct a lot more scientific research before we do

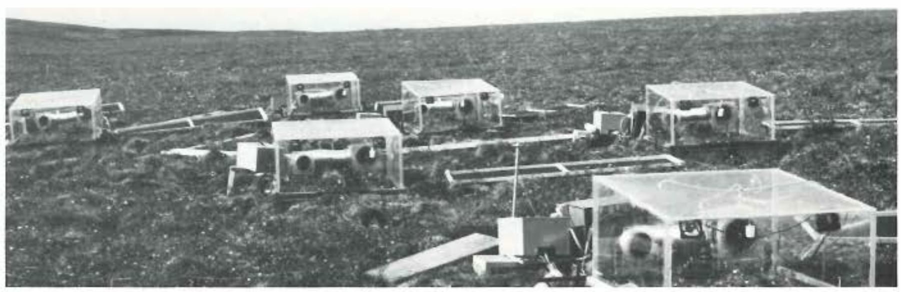
Measuring the Changes Through Laboratory and Field Studies

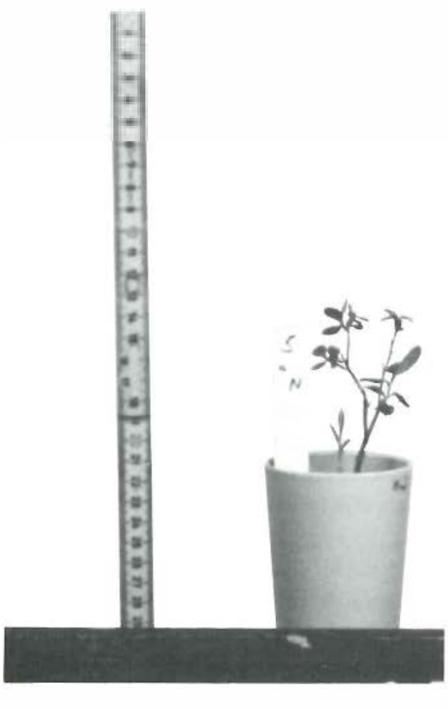
The global dimensions of the greenhouse effect require a correspondingly global research effort. Air sampling at remote sites from the tropics to Alaska and Antarctica is helping to identify the sources and sinks of CO_2 and other heat-absorbing gases. Field and laboratory studies on carbon uptake by plants exposed to various CO_2 levels are building understanding of the factors influencing the buildup of atmospheric CO_2.

Sampling air for greenhouse gases



Measuring plant response to CO_2





anything else. "We simply do not know enough yet to respond intelligently," he asserts. "There are vast uncertainties in the carbon cycle, in the response of vegetation, in the coupling of oceanic and atmospheric processes, and in the way these factors will interact to change our environment. There are also gaps in our data on regional and seasonal climate change and in our understanding of the consequences of that change. We need another 10 years of concerted interdisciplinary research to resolve these uncertainties. By then we will have a clear enough understanding of the processes involved to give policymakers and the public the information necessary to make sound decisions."

Many scientists believe that although our understanding is incomplete, we do know enough to mitigate the greenhouse effect. "If uncertainty is a ground for no action," says Schneider, "then we would have no insurance companies and no armies." Energy policy is often identified as one area in which much could be done to reduce CO_2 emissions. Greater emphasis on end-use efficiency, certain renewable energy resources, and nuclear power are all pointed to as ways of providing energy without releasing CO_2. An examination of the sources of man-made CO_2 emissions, however, reveals that any effective effort to curb CO_2 releases would require extensive international cooperation.

Moreover, the fact that trace gases are fast approaching CO_2 in their greenhouse potency means that they too would have to be considered in an international effort to mitigate the warming. Controlling trace gases will not be easy. "If methane and nitrous oxide are rising as a consequence of a human activity as essential as food production," comments Cicerone, "it's going to be very difficult to limit their increase by agreed-upon social and political changes."

Dennis Tirpak directs a program looking at the effects of climate change for the Office of Policy Analysis in the U.S. Environmental Protection Agency (EPA). Tirpak and his colleagues maintain that society should begin exploring ways to adapt to the expected changes. "Ninety-nine percent of the government's efforts in this area are directed toward research on the mechanisms that may lead to climate change," reports Tirpak. "Very little emphasis is being placed on assessment and analysis of what this could mean for society and for the environment." Tirpak cites the recommendations of an international conference on the greenhouse effect held last October in Villach, Austria, calling for more assessment work in parallel with scientific research.

"Many important economic decisions are being made today," read a statement issued by the conferees, "on major irrigation, hydropower, and other projects; on drought and agricultural land use; on structural designs and coastal engineering projects; and on energy planning—all based on assumptions about climate a number of decades into the future."

Tirpak explains that EPA is supporting some "what if" studies that make assumptions about future climate and then explore potential adaptive strategies. One study now under way looks at the effects of a greenhouse warming on utilities. EPRI is a cosponsor of this research, along with EPA, Edison Electric Institute (EEI), and New York State Energy Research and Development Authority (NYSERDA).

Much to learn

Regardless of their views on whether we should be focusing exclusively on unraveling the scientific uncertainties or developing responses to the greenhouse effect, scientists agree that we still have much to learn about the ways in which human activities are influencing climate.

Keeling reflects, "The main problem with climate impact of CO_2 and other gases is that we don't like to see change. We don't want to face rising sea level, for example, because it means we'll have to move a lot of people around. The earth has seen it all before, though. The cycle was never in balance. CO_2 has been far higher and far lower in the geologic past. Climate has been warmer and colder, too. We don't know how fast the changes now under way will come or how far they will take us, but we do know that the decisions we make today will have implications far into the future. The memory of the fossil fuel era will be with the earth for tens of thousands of years." ■

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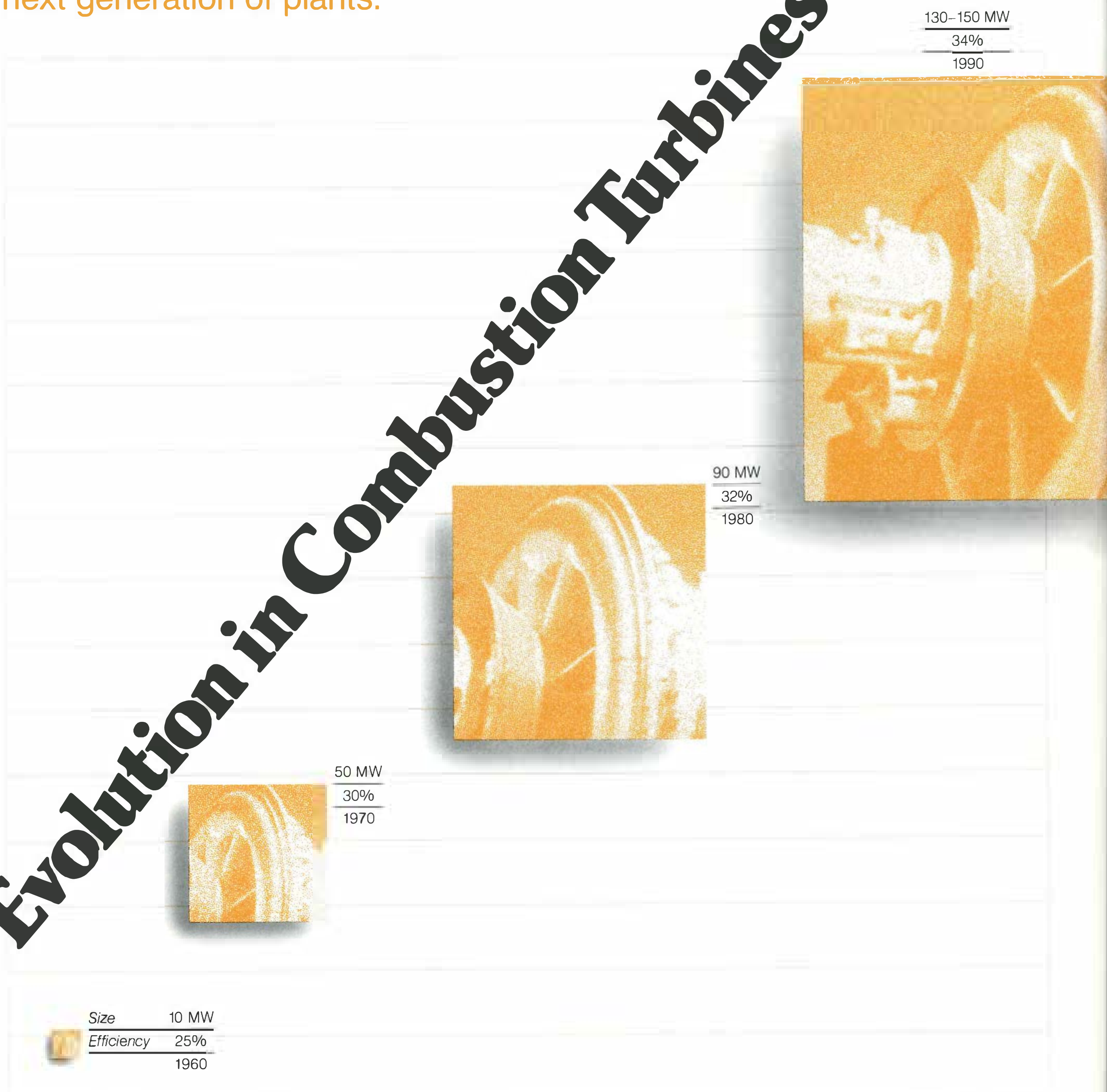
This article was written by Michael Shepard. Technical background information was provided by Charles Hakkarinen and Alan Hansen, Energy Analysis and Environment Division, and Dwain Spencer, Advanced Power Systems Division. Additional support was provided by Mary Ann Allan, Seymour Alpert, Glenn Hilst, Ralph Perhac, and Thomas Wilson.

Evolution in Combustion Turbines

Increasing in size and efficiency at regular intervals, combustion turbines have become an attractive option for utilities seeking small increments of new capacity. A decade of work on turbine reliability is culminating in advanced designs that promise higher availability in the next generation of plants.



Combustion turbines have been used since the late 1940s to provide electric power at times of peak demand. But because the turbines were inexpensive and because they were used only a small fraction of the time, utilities did not put as much effort into maintaining these machines as they devoted to their baseload plants. As a consequence of minimal maintenance, demanding operation, and materials and design limitations, combustion turbines experienced frequent forced outages and acquired a reputation for being unreliable. They were also relatively inefficient, a characteristic that has improved in later models and that was of only minor concern when fuel was cheap.

When oil and natural gas prices rose in the late 1970s, the operation of combustion turbines became far more expensive. Congress passed the Fuel Use Act of 1978, banning utilities from installing after 1992 any additional intermediate or baseload capacity fired with oil or natural gas for more than 1500 hours a year. The restrictions of this law, coupled with reliability concerns and high fuel prices, caused the bottom to fall out of the domestic utility combustion turbine market. Sales to American utilities plummeted from almost 9000 MW in 1971 to near zero between 1980 and 1982.

Today, with fuel prices falling and utilities anxious to minimize capital expenditures and risk by adding capacity in small, modular increments with short lead times, utilities are once again purchasing or considering combustion turbines, both as stand-alone units and in phased combination with conventional steam turbines and coal gasifiers. If the notion of phased construction catches on, as some utilities are currently projecting, the way utilities plan and build new power plants could change dramatically.

A different kind of power plant

Combustion turbines are versatile devices. They are used by numerous chemical and process industries to provide mechanical and electrical power, by the aviation industry as airplane engines, and by U.S. utilities to drive more than 50,000 MW of electric generators.

Unlike coal and nuclear plants that use heat from burning or reacting fuel to generate steam that spins turbine generators, combustion turbines use air as the working fluid. Air is compressed and injected at high pressure with fuel—usually natural gas or oil—into a combustion chamber, where the mixture burns and then expands through a turbine at about 1093°C (2000°F). Sometimes known as a gas turbine (referring not to the fuel but to the fact that combustion gas drives the turbine), the combustion turbine's name is misleading because the turbine is actually just one component of the power plant.

Combustion turbines have grown in size and efficiency over the years. In the 1950s and 1960s manufacturers produced small turbines, of 10–25 MW, aimed principally at the aircraft market. Typical efficiencies (lowering heating value) in that period were 23–30%. Utilities bought many turbines that were essentially retrofited jet engines. They were inexpensive and compact, and they came on-line quickly when they were needed. Consolidated Edison Co. has long maintained a number of small, heavy-duty turbines on barges on the East River and fires them up to help meet New York City's demand peaks. Many other utilities put combustion turbines to similar use.

As utilities and other industries made more use of combustion turbines, manufacturers started to produce larger and more-efficient models, reaching 50 MW around 1970 and 90 MW by 1980 with efficiencies of about 32%. "Combustion turbines tend to evolve in cycles of 10 to 15 years, for both technical and market-oriented reasons," explains Albert Dolbec, EPRI's senior program manager for power generation. "It takes that long to develop and test new materials and component designs. And because utilities are not inclined to buy any equipment that hasn't been proved in extensive testing, the manufacturers are reluctant to be the first to offer new models." But changes do come, and Dolbec claims that the major manufacturers are on the verge of offering a new generation of combustion turbines for shipment after 1988, with typical sizes of 130–150 MW and efficiencies of 34%.

To increase combustion turbine efficiency, manufacturers had to make the machines run at higher temperatures because efficiency is determined in part by the temperature of the hot gas entering the turbine. Hotter operation, however, demanded more-advanced materials and cooling designs. The hot gas temperature in these machines (1260°C [2300°F] in the next-generation models) is far hotter than the turbine blades can withstand, so the metal is cooled with extracted compressor air to 816–871°C (1500–1600°F). Improvements in combustion system design, better methods of cooling with air, and materials improvements in the hot section parts (combustion liner/basket, transition piece, turbine vanes and blades) have made it possible to raise operating temperatures.

Utilities and other combustion turbine users have benefited extensively from the massive ($750 million in 1986) R&D effort the military devotes to improving turbine technology. Although the military's principal concern is to improve jet engine performance, manufacturers have been able to apply many of the advances developed for military applications (such as high-temperature materials and aerodynamically more-efficient compressors) to commercial combustion turbines for the utility market.

A flexible option

One of the most flexible features of combustion turbines is that they can be operated alone in what is termed an open or simple cycle, or their hot exhaust gas can be used to generate steam to drive a conventional steam turbine in an approach called a combined cycle. Combined cycles have a number of advantages that are making them attractive to utilities considering capacity expansion.

They are the most efficient of all thermal power plant designs, converting up to 47% of the fuel energy into electricity. Combined cycles also have great fuel flexibility, as combustion turbines can operate on natural or coal-derived gas and on various grades of fuel oil. In fact, some combustion turbines can change fuels without shutting down and some can burn mixtures of fuels. Coal gasifiers can be added to a combined-cycle plant site, enabling the plant to run on synthetic gas if natural gas or oil is too expensive or unavailable. Such integrated gasification–combined-cycle (IGCC) systems are receiving increasing attention in the wake of the successful operation of the 100-MW IGCC demonstration plant at Southern California Edison Co.'s Cool Water station.

Because these systems can be built in stages as the need for new capacity grows, they have important financial benefits as well. Phased construction allows utilities to pay for small increments of capacity as they come on-line rather than have to invest huge lump-sum amounts in baseload plants many years before they will operate. By deferring capital expenditures on new capacity until it is needed to meet incremental load growth, utilities can reduce interest payments, lower their debt burden, and protect themselves from having "imprudent" building costs questioned by regulators.

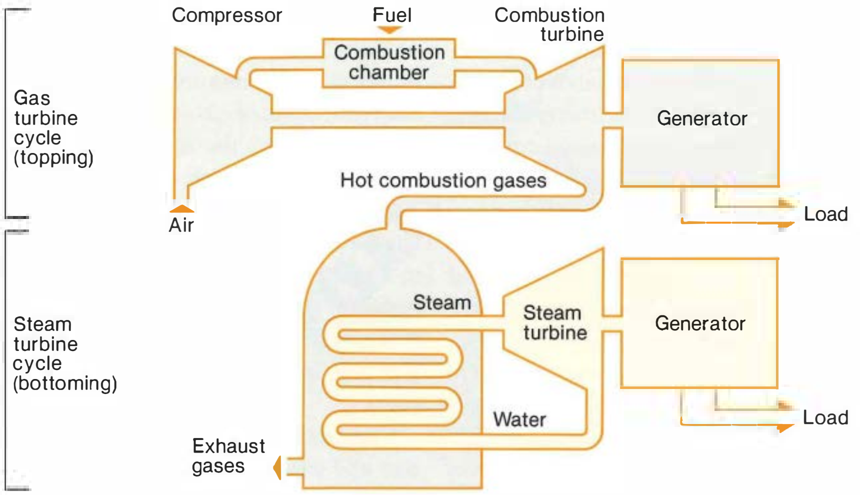
One of the greatest advantages of systems built around combustion turbines is their good environmental performance. Combustion turbines have very low pollutant emissions, particularly when run on natural gas or cleaned syngas made from coal, and can operate under the strictest environmental regulations.

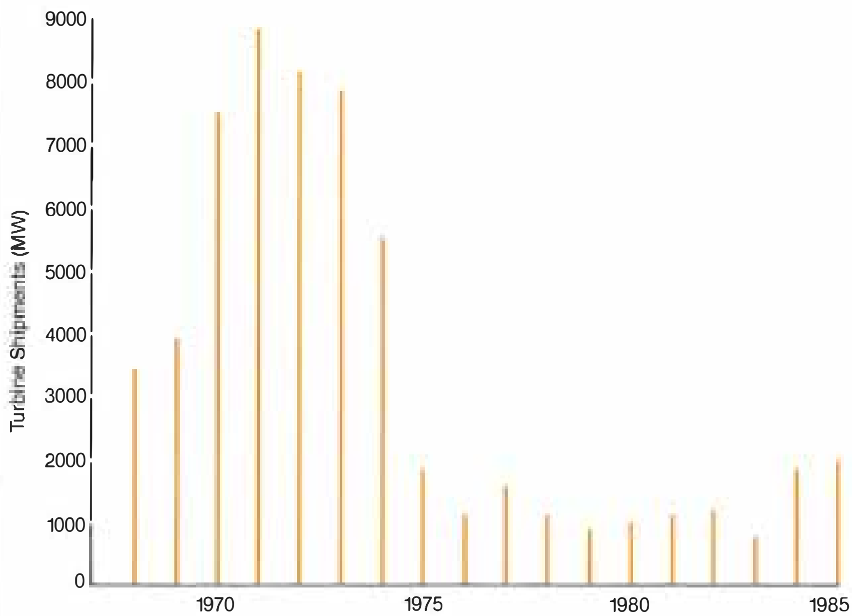
Utility interest is growing

Thanks to the flexibility and risk reduction that combustion turbines and combined-cycle systems offer, many utilities are exploring these options in their generation planning. Some are interested in

Combined-Cycle Power System

A combustion turbine and a steam turbine can be linked in a combined-cycle system to increase efficiency. Compressed-air and fuel (natural gas or oil) burned in the combustion chamber produce hot gases that first spin the gas turbine in the topping cycle. The gases are then diverted to the bottoming cycle, where their heat is used to boil water and produce steam, which turns the steam turbine linked to a second generator. Combined cycles are the most efficient of all thermal power plants, converting up to 47% of the fuel energy into electricity.





Combustion Turbine Shipments to Domestic Utilities

In the late 1960s and early 1970s when electricity demand was growing rapidly and fuel was cheap, utilities purchased many combustion turbines, mostly to meet peak power needs. As oil and natural gas prices soared following the Arab oil embargo of 1973, American utility purchases of new combustion turbines plummeted and have stayed low ever since. Today, with oil and gas prices falling and utilities looking for ways to add capacity in small increments, many utilities are once again ordering or considering new combustion turbines.

simple-cycle combustion turbines strictly for peak power needs. Texas Utilities Co., for instance, recently received approval from its public utility commission to install 960 MW of combustion turbine capacity by 1990. In addition, the utility's current resource plan calls for an additional 500 MW of combustion turbines by 1994. According to Donald Deffebach, Texas Utilities' manager of power supply planning, "The 960 MW of combustion turbines will be used principally to meet peak power needs, but design of the sites will provide for future conversion to combined cycle."

David D'Amico, a power engineer with Boston Edison Co., explains that his utility is also planning to meet a growing peak demand with new combustion turbines. "We have an application pending to license a site for one simple-cycle combustion turbine about 85 MW in capacity. If the license is approved and the company decides to proceed with this option, we will probably install it before 1990."

Other utilities, in looking ahead to their need for new baseload capacity in the 1990s, are considering phased construction of combined-cycle and IGCC systems. In late 1984, 11 utilities joined EPRI in a project to analyze the merits of phased capacity expansion, starting with combustion turbines. "The economics of phased construction are very site-specific," explains Michael Gluckman, who directs engineering and economic evaluations for EPRI's Advanced Power Systems Division. "There are many ways in which to build combinations of combustion turbines, steam bottoming cycles, and coal gasifiers, and what's good for utility A may not be useful for utility B. We wanted to learn how phased construction looked under a variety of conditions."

EPRI began by preparing a data base with cost and performance figures on nine phase-in strategies. The data included information on fuels, heat rates, availability of individual components, part load performance, equipment cost, and other factors. The information was adapted to fit with the PROMOD production costing model that many utilities use to project costs and performance of the generating options they are considering.

The participating utilities then used these data to evaluate phased construction for their systems. "Eight of them have completed this exercise," says Gluckman, "and each has found that some plan involving combustion turbines is the optimal choice for system expansion." Some find that combustion turbines alone are what they need, others find combined-cycle systems to be their best option, and still others see IGCC as their preferred approach.

Potomac Electric Power Co. (Pepco) is sufficiently convinced that phased construction meets its needs, and the utility recently launched a preliminary planning study to add two 120-MW combustion turbines by 1996, followed by a 120-MW steam bottoming cycle and a coal gasifier later in the decade. "Our calculations show that by building the project in phases, we can save about $120 million in present-value costs over the 30-year life of the plant, compared with building a conventional coal-fired baseload plant of similar capital cost all at once," explains Pepco's Thomas Welle. Licensing, engineering, and environmental field monitoring work on the project is already under way.

Virginia Power, another utility participating in the EPRI study on phased construction, also concluded that this is currently a least-cost way for it to expand its capacity. Daniel Danforth, corporate engineering adviser at Virginia Power, explains, "We expect our next new generating capacity to be a modular facility with 200 MW of combustion turbine and steam bottoming cycle. Addition of a coal gasifier, when economically justified, will provide fuel flexibility for this unit. Although decisions on generation expansion after this unit have not been made, phased, modular, combined-cycle units do figure in our planning."

Florida Power & Light Co. recently developed a capacity expansion plan calling for phased construction of about 1200 MW of combined-cycle units by the year 2000. William Smith, manager of power supply planning for FP&L, states, "We want to design the systems with the option of adding gasifiers later, but for now we are just considering combined-cycle units. We expect to need our first increment of capacity, totaling about 600 MW, in 1995."

Because they are small, combustion turbines have the flexibility of fitting into existing sites. This feature makes combustion turbines particularly attractive to utilities that want to repower plants. Consumers Power Co. recently announced a proposal to install 1160 MW of combustion turbines in two phases at Unit 1 of its canceled Midland nuclear plant. Steam raised from the combustion turbine exhaust heat will be used to power the steam turbine already installed in the plant. The utility is now awaiting PUC approval to launch engineering studies on the project. Other utilities now facing cancelation decisions on nuclear plants will be watching the Consumers Power experience closely to see how the gas turbine retrofit strategy works at the Midland plant.

Combustion turbine retrofits are not limited to nuclear sites. Northeast Utilities is considering the installation of three combustion turbines totaling about 400 MW to repower four oil-fired steam turbines at its Devon station. A coal gasification facility might be added later. It's too early to be sure, but these and other signs point to a sea change in the industry, with utilities looking very seriously at combustion turbines and combined-cycle systems to meet much of their demand growth for the rest of the century.

But what about reliability?

Despite the attractive features of low cost, fuel flexibility, modularity, and good environmental performance, there are still concerns within the utility industry about the reliability of combustion turbines and combined-cycle systems. A number of factors have converged recently, however, to assuage some of the utilities' doubts.

The EPRI-supported Cool Water IGCC station operated at more than 50% of rated capacity in 1985. The excellent performance of this first-of-a-kind plant has raised considerable interest in utility circles. Utilities are also carefully watching the performance of combined-cycle industrial cogeneration systems, which have mushroomed over the past several years. The success of these systems is undoubtedly affecting utility perceptions of combustion turbine technology. Moreover, 10 years of EPRI work in combustion turbine reliability has led to greater emphasis by manufacturers on high-reliability designs and to greater confidence among utilities that with appropriate maintenance, combustion turbines can be very reliable.

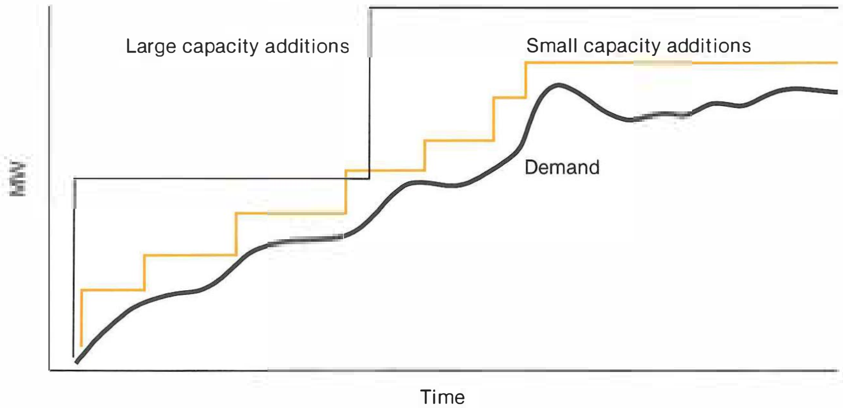
In 1976 EPRI asked utilities for their suggestions on the kind of research the Institute should perform on combustion turbines. The utilities replied unanimously that their greatest concerns were in the reliability area and that was where EPRI should focus its efforts. No one had ever before made a systematic accounting of the causes of combustion turbine failures. Working with a group that has since become the combustion turbine task force of the Edison Electric Institute's prime mover committee, EPRI launched an effort to focus on combustion turbine failure rates.

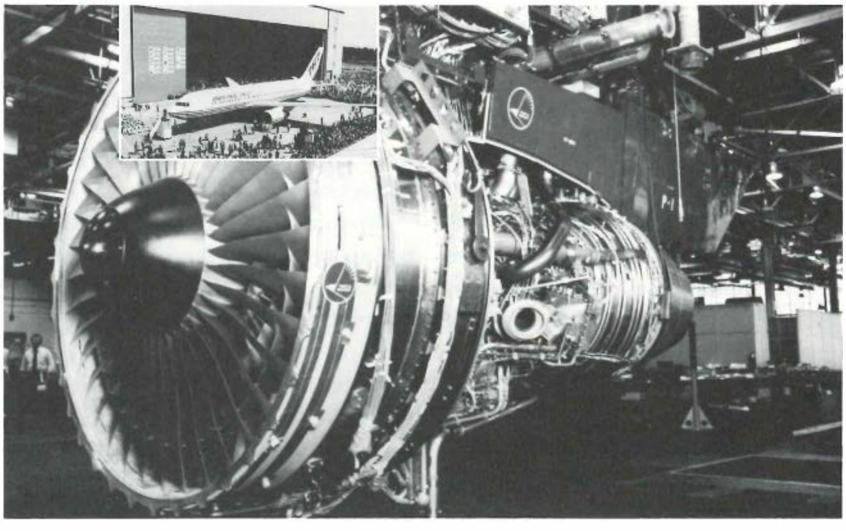
This effort was inspired in part by the realization that reliability in combustion turbines has historically improved only with the discovery and correction of problems in the field—at considerable cost to utilities. EPRI's Dolbec documents this claim with a graph plotting availability against hours of operation for one model of turbine introduced in 1972. The graph shows a big dip in availability during the first five years. "What that means," he says, "is that the utilities were having to work the bugs out of these systems as they arose. That translates to a lot of expensive downtime and big repair costs that would have been reduced if the manufacturers had put more emphasis on reliability while they were designing the machines." Having borne the cost and inconvenience of component failures and outages over the years, utilities wanted to gather the information needed to define reliability goals that manufacturers could aim for before releasing new models to the market.

The first round of data collection and analysis, completed in 1981, yielded a general picture of the frequency of turbine outages, but it did not dig deep

Inching Up the Demand Curve

In an effort to reduce risk and capital expenditure in meeting uncertain future load growth, utilities today are shunning investment in large new baseload plants and are instead seeking ways to add new capacity in small increments with short lead times. Combustion turbines are well suited to this strategy, whether added alone for peaking capacity or as part of modular construction of combined-cycle or IGCC plants to meet baseload needs.





The Link to Aircraft Engines

Utility combustion turbines have evolved from turbines used for aircraft engines. Most of the R&D on combustion turbines is conducted by the military, which last year in the United States spent $750 million to improve these machines. Better turbine materials and designs developed by the military often find their way into commercial combustion turbines, allowing utilities to benefit directly from the Pentagon's R&D.

enough to reveal the root causes of the failures. Beginning in 1982 EPRI funded development of a more detailed data base on the causes of turbine outages. Operating data from 12 utilities revealed that about 60% of combustion turbine outages are caused by failures in controls and accessories, including temperature controls and monitors, fuel supply equipment, starters, and pumps for lubricating oil, water, and air.

This pinpointing of problem areas enabled EPRI to initiate a follow-up project with General Electric Co. to examine the potential for improving controls and accessories on the next advanced model combustion turbine. Looking at forced outage data on 170 General Electric combustion turbines from 1977 to 1982, the study established quantitative reliability goals for new plant designs and developed methods for analyzing the reliability of individual components and systems. General Electric incorporated the findings of this study into its design work on new advanced models. For the first time, utility concerns about reliability are being translated into equipment improvements before the machines are released.

In addition to helping EPRI focus its research effort, the combustion turbine reliability data base is a tool that utilities can use and benefit from directly. Charles Knauf, manager of the combustion turbine division for Long Island Lighting Co., was instrumental in starting the data base and has been working on it directly for the last two years as a loaned employee to EPRI. "Combustion turbines have historically been the stepchildren of the utility business," he observes, "getting just enough attention to get by." With more-systematic operation and maintenance guided by the reliability data base, he believes utilities could obtain far more effective and reliable service from their combustion turbines. "Some maintenance procedures are performed more frequently than necessary. Others aren't done often enough. Utilities can use the data base to develop an optimal maintenance program that will save them money in the long run."

Knauf explains that with the high operating temperatures of combustion turbines, parts can degrade and crack, sometimes breaking off small pieces of metal that can cause major damage if they pass through the turbine section of the machine. A single turbine blade can cost up to $5000; replacing the entire first row of turbine blades can cost half a million dollars. To shut down and thoroughly inspect a combustion turbine, however, costs $15,000 to $25,000. The challenge then is to spend a moderate amount on maintenance so as to avoid the large expenses that arise from catastrophic or even moderate failures.

Using industrywide figures from the data base on performance and failure rates of various turbine models and components, utilities can draw curves plotting the probability of a given part failing within a certain number of hours against the cost or number of man-hours required to repair such a failure. Focusing first on those failures that are most likely to occur and will be most costly to repair, the utility can then use the data base to determine how to avoid such failures in a cost-effective manner.

Suppose the part in question has only a 20% probability of failing within 200 hours of operation but a 90% probability of failing within 400 hours—this is the kind of information the data base provides. The utility then knows it can run the equipment for 200 hours with little risk of failure but that it should inspect the part somewhere between 200 and 400 hours to avoid a far greater risk of failure. Conversely, there is little need to regularly inspect a part that is statistically likely to run failure-free for 25,000 hours. This probabilistic approach to maintenance planning offers no guarantees—a part can fail immediately after inspection—but it does enable utilities to operate with the odds on their side.

All this work should, on paper, help to improve combustion turbine reliability. But the only way to know for sure how a piece of equipment will perform is to turn it on, wait, and watch. The final part of EPRI's combustion turbine reliability program proposes to do just that. EPRI is now seeking a host utility willing to participate in a durability test of General Electric's new model combustion turbine. Clark Dohner, project manager for high-reliability combustion turbines explains, "The host utility must be an early purchaser of the next generation turbine. We will instrument and monitor the turbine and run it through a series of stringent duty cycles over a five-year period to test the durability and reliability of the system and its advanced components. Our goal is to get the early failures out so they can be corrected before many units are sold to utilities."

"The timing couldn't be better," says Dolbec. "The spade work utilities have sponsored in combustion turbine reliability is starting to pay off with improved components, designs, and O&M strategies just as the market for these machines seems to be growing again." How closely utilities will embrace combustion turbines and combined cycles in the years ahead remains an open question. But there is little doubt that the next generation of these power plants will be more efficient and reliable than its predecessors. ■

Further reading

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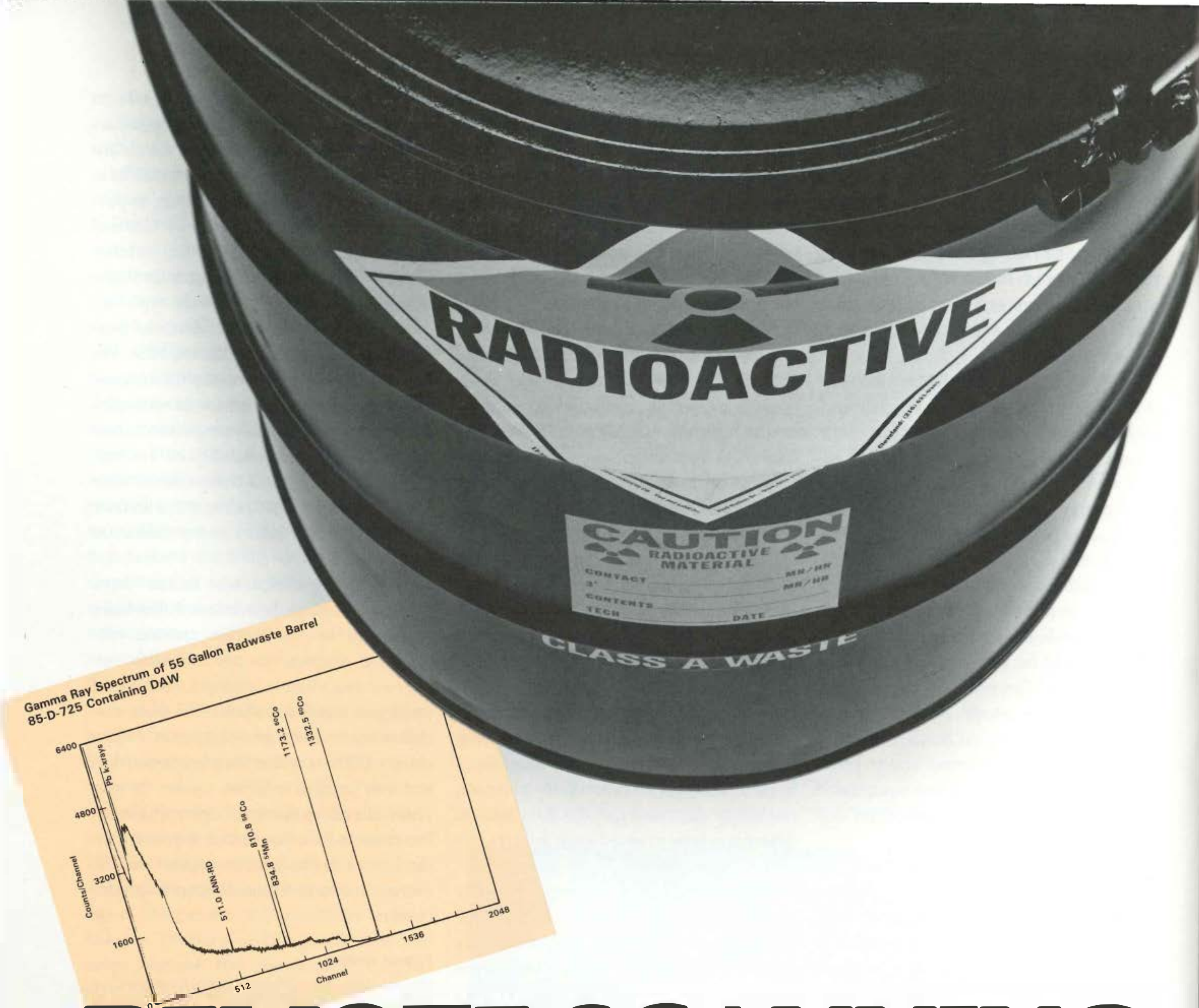
This article was written by Michael Shepard. Technical background information was provided by Albert Dolbec, Clark Dohner, and Michael Gluckman, Advanced Power Systems Division. Additional support was provided by Charles Knauf, Ronald Wolk, and Stanley Vejtasa.



REMOTE SCANNING OF LOW-LEVEL WASTE

How hot is that drum of low-level radwaste? Two new assay methods read radiation levels directly from outside the waste container and determine its content of specific radionuclides. These techniques improve accuracy and avoid the risk and high cost of extracting samples for laboratory analysis.

For nearly the last six years, utility low-level radioactive waste (LLW) management programs have been driven by regulations and laws directed to the operators of licensed commercial disposal facilities. The Low-Level Radioactive Waste Policy Act of 1980 mandated that states assume responsibility for disposal of LLW generated within their borders by January 1, 1986. As that deadline neared with only three disposal sites available, Congress gave utilities, hospitals, research laboratories, and other generators of LLW an eleventh-hour reprieve late last year.

Lawmakers extended this deadline through 1992 for states to form regional compacts and establish new disposal sites, but they also amended the LLW act to allocate remaining capacity at current sites and set progressive surcharges on waste volumes based on the degree of progress of individual states in establishing new sites.

While states struggle through the political and institutional difficulties of cooperatively setting up new disposal sites, industries that produce LLW face a problem complying with separate Nuclear Regulatory Commission (NRC) rules related to the licensing of facilities for LLW disposal. These rules require utilities and other LLW producers to identify and quantify individual radionuclides prior to shipment for burial.

In place since 1983, NRC's Licensing Requirements for Land Disposal of Radioactive Waste—Title 10, Section 61 of the Code of Federal Regulations (CFR)—have posed a dilemma for many utilities operating nuclear power plants. The rules specify that wastes be classified in one of three categories based on the limiting concentrations of some 16 specific (and hard to measure) radionuclides; the more hazardous categories include certain waste form and stability requirements.

"The 10CFR61 requirements cannot be met with radiation detection equipment currently available on-site at nuclear power plants," notes Patricia Robinson, a project manager in EPRI's Nuclear Power Division. "Nuclear plants have had to sample wastes and radiochemically analyze the samples for their isotopic content at off-site laboratories. The cost of this approach can range from $30,000 to $200,000 a year per plant.

"Not only is this practice costly, but it may result in unrepresentative samples and lead to additional personnel radiation exposure, and some wastes—such as neutron-activated components—may be too radioactive to sample in a practical manner," explains Robinson. "In addition, because of sampling inaccuracies, the typical practice of estimating isotopic content from dose-rate measurements often leads to very conservative overestimates of total radioactivity, which in turn lead to unnecessarily excessive disposal costs. Research results indicate that some isotopes may be overestimated by factors of 1000 to 10,000."

Anticipating the need for better assay tools and techniques for LLW, EPRI is pursuing the transfer into utility use of two technologies that offer substantial improvement in accuracy and simplicity over existing sampling and radiochemical assay or calculation methods. In addition, both of these are direct-assay methods and promise to satisfy NRC criteria for keeping personnel radiation exposure as low as reasonably achievable (ALARA) because they permit scanning of entire waste packages without requiring workers to open containers or withdraw samples.

One, a technique for determining the content of transuranic (TRU) isotopes (those with atomic numbers greater than uranium) in a waste volume, was originally developed under a Department of Energy (DOE) contract. The second, a commercially available technology, employs collimated high-resolution spectroscopy to measure the gamma activity in bulk waste. Results from both types of measurement become input to microcomputer codes that calculate individual concentrations of TRU and gamma-emitting radionuclides. If concentrations of key isotopes are known, plant-specific scaling and dose-to-curie correlation factors can then provide reliable measurement of the amounts of all isotopes in waste shipments.

Both technologies have now been successfully demonstrated in cosponsorship with Florida Power Corp. at the utility's Crystal River nuclear plant, following earlier individual testing at other plants. Used in combination, the TRU and gamma-scanning techniques may revolutionize the technical means for compliance with federal LLW regulations and reduce sampling uncertainties and the cost of disposal in the process.

"Eventually, direct assay of LLW could be commonplace at all nuclear plants," says Robinson. "Both of these technologies are acceptable to NRC as alternatives to radiochemical sampling and analysis. With the trend in federal requirements for LLW and the economic pressures tied to burial site capacity, the benefits of these technologies are clear. Our job now is to transfer the technology so that it is commercially available to the industry."

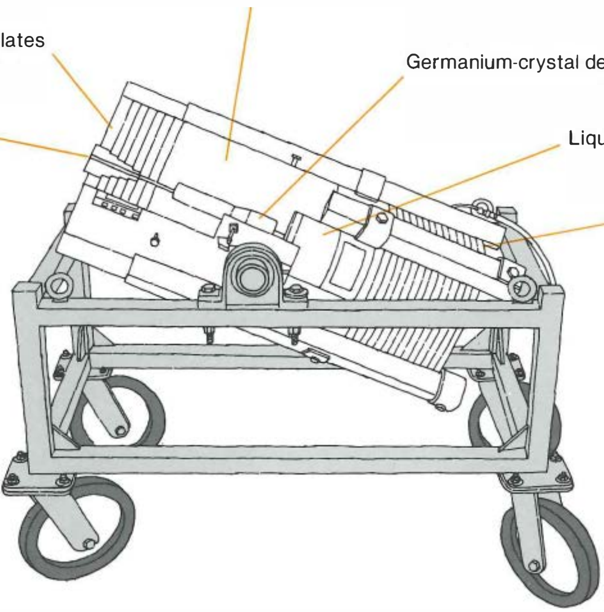
Transuranic assay

Various forms of LLW contain trace quantities of transuranic elements that are byproducts of fission of the uranium fuel, including several isotopes of plutonium, americium, and curium. New waste classification limits require quantification of these specific radionuclides, but their detection and precise measurement in a volume of waste is masked by radiation from other isotopes in the waste. Until recently, sampling and destructive radiochemical analysis was the only way around the problem.

Under a DOE contract, Battelle, Pacific Northwest Laboratories developed a technology that permits direct assay of LLW packages for TRU content by detecting the neutrons emitted from the waste package. The neutrons are produced by spontaneous fission of the TRU isotopes or by the collision of alpha particles with lighter isotopes in the waste. A simple computer code converts the to-

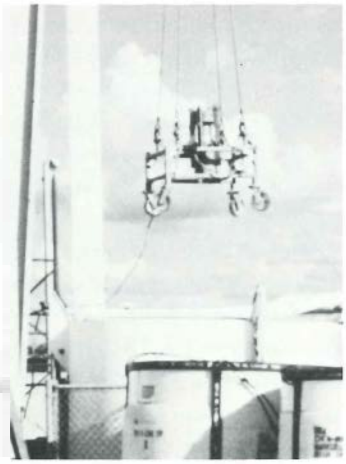
Direct Assay for Gamma-emitting Nuclides

Science Applications International Corp.'s QuantiScan system provides a direct-assay method for determining the content in LLW of isotopes that emit gamma radiation, including those of cobalt and cesium.

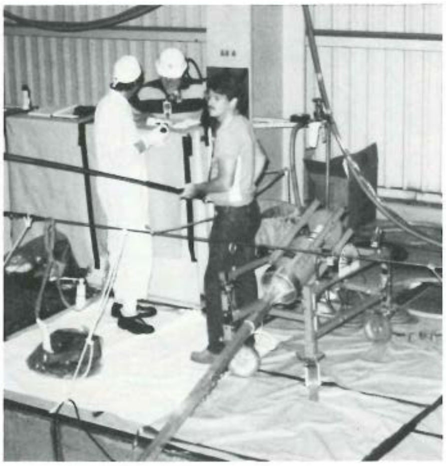


The system employs a high-purity intrinsic semiconductor material—germanium—in its core that exhibits significant changes in conductivity when exposed to gamma rays. A tungsten collimater focuses gamma radiation entering the germanium detector, which is cooled by liquid nitrogen and otherwise shielded with tungsten and lead.

Mounted on a cart and pointed at a waste drum or suspended over a liquid waste container by crane, the QuantiScan is connected to other electronic instruments and a computer that converts the gamma measurements to distributions of individual gamma-emitting isotopes. An extension to the collimater permits gamma-scanning of irradiated hardware in a spent-fuel pool.



In position over liquid resin tank.



Assay of irradiated hardware under water.

Electronic instruments and computer.

tal neutron count into individual isotope concentrations in units of nanocuries (billionths, 10^{-9}, of a curie) per gram of waste. Radiochemical analyses of some irradiated materials scanned by the TRU system indicate an accuracy within 0.1%.

The prototype TRU Detection System was originally built for use at the government's Hanford nuclear reservation in Washington State, but has since been demonstrated at several commercial nuclear power plants under an EPRI demonstration project. The system employs a cylindrical array of ninety-six 9.8-ft-long (3-m), 2-in-diam (5-cm) tubes filled with boron trifluoride ($^{10}BF_3$) that surround the waste container. The tubes are mounted in polypropylene that slows down, or moderates, neutrons from the waste. Each neutron is electronically recorded by the $^{10}BF_3$ tubes.

The detector can be calibrated for a variety of containers and materials, including solidified resin and filter media in concrete-lined drums. For typical measurement of a 55-gal drum, the container is centered inside the tube bank and counted for 10 min. An 8-in (20-cm) lead shield around the waste container protects the detector from excessive gamma radiation.

Demonstrations sponsored by EPRI of Battelle's TRU detector were conducted in 1984 and 1985 at Wisconsin Electric Power Co.'s Point Beach nuclear plant, Philadelphia Electric Co.'s Peach Bottom station, and Florida Power's Crystal River nuclear plant. About 40 waste containers (with dose rates up to 2 R/h) assayed at the plants showed less than 10 nCi/g of total TRU radionuclides—the federal limit for the least restrictive class of LLW. The approximate limit of detection sensitivity in the demonstration applications, about 1.5 nCi/g, could be lowered to 0.5 nCi/g of total TRU by extending the counting time to 100 min.

A similar unit has also been configured for underwater operation to measure TRU contents associated with highly radioactive components from inside a reactor that are stored on-site in spent-fuel pools. The underwater system, composed of 29 somewhat shorter (26-in, 66-cm) $^{10}BF_3$ tubes encased in lucite moderator and housed in a watertight stainless steel box, was demonstrated at Crystal River. Six cannisters of in-core waste components with dose rates of 7000–22,000 R/h showed average TRU concentrations of about 2 nCi/g—the approximate limit of detection sensitivity for a 1000-min exposure.

The TRU detector's proven capability leads researchers to believe it could be economically cost-effective if available as part of a commercial service. Given an estimated capital cost of $300,000, few utilities could justify purchasing one. But even if a utility wanted to buy one now, it could not. Paid for and patented by DOE, the system faces some hurdles before it sees wide use in the utility industry. EPRI is participating in a technology transfer effort with DOE that could soon make the system available through a nuclear services vendor.

Direct gamma-scanning

In addition to requirements for more-accurate assays of transuranic isotopes in LLW, NRC regulations have also increased analysis and reporting requirements for gamma-emitting radionuclides, including various isotopes of cobalt and cesium.

The gamma-emitters are present at fairly low concentrations and produce low levels (from thousandths of a rad to a few rads per hour) of radiation in typical LLW material, but they also account for the much higher radiation levels in irradiated in-core hardware, where the high neutron flux can produce gamma-dose rates of up to several tens of thousands of R/h in in-core instruments, core barrel bolts, and control rod retainer clips. Such components are handled remotely and stored in steel cannisters underwater in spent-fuel pools.

NRC rules require quantification of the gamma-emitting isotopes in LLW, but for some types of material, representative sampling and radiochemical assay, again, is impractical or inaccurate because of the nonuniformity of the waste or because of high dose rates. This is true especially for irradiated hardware, where scrape sampling and radiochemical analysis entail substantial uncertainties and potential personnel exposure.

A device for direct assay of gamma-emitters in waste has been commercially available since 1984 from Science Applications International Corp. (SAIC), under the trade name QuantiScan. The heart of the system is a high-purity crystal germanium detector cooled by liquid nitrogen and encased in a shielded collimator. A low-power laser assists in alignment for waste scanning. A 5-in (12.7-cm) lead shield on the front of the unit allows it to operate in background radiation fields of several R/h. The unit is mounted on a cart and connected to a portable microcomputer up to 200 ft (61 m) away that controls the acquisition, analysis, and reporting of data. The electronics package includes a high-count rate amplifier and analog-to-digital converter.

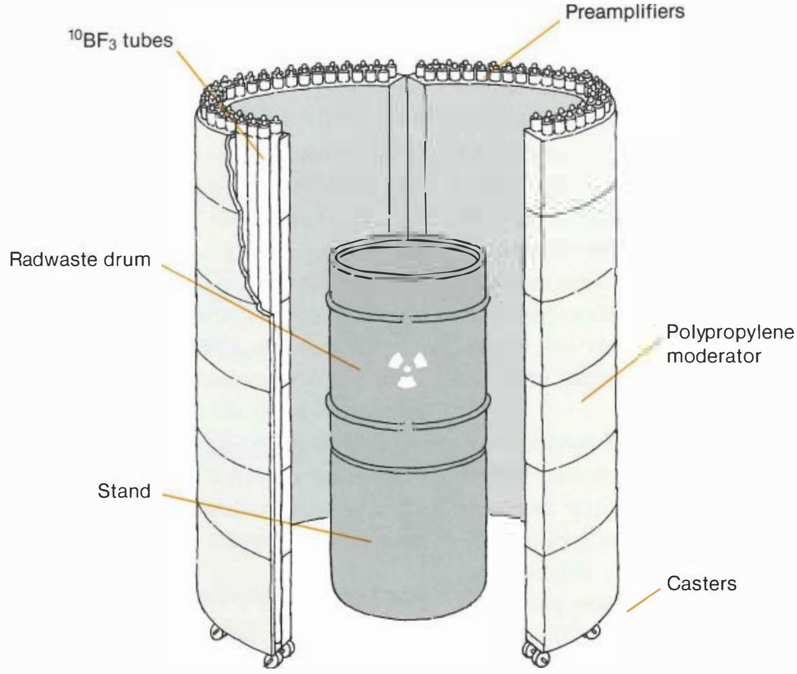
SAIC has demonstrated the QuantiScan system in a number of applications. The device was used in the cleanup operation at TMI-2 to help locate fuel debris in the crippled reactor. EPRI sponsored demonstrations at three operating plants in 1984 and 1985, in which SAIC assayed various waste forms, including filter cartridges and bulk resin in high-integrity containers, demineralizer resin transfer lines during sluicing, solidified evaporator concentrates, and dry active waste in drums and boxes. In addition to these EPRI-sponsored demonstrations at Point Beach, Peach Bottom, and Crystal River reactors, the QuantiScan has been used at Virginia Power's Surry reactor and Rochester Gas and Electric Co.'s Ginna station.

At Crystal River, direct samples for radiochemical analysis and dose rate measurements were taken for most of the wastes for comparing the results with those of the QuantiScan. Results from direct gamma assay were combined with plant-specific scaling factors to obtain

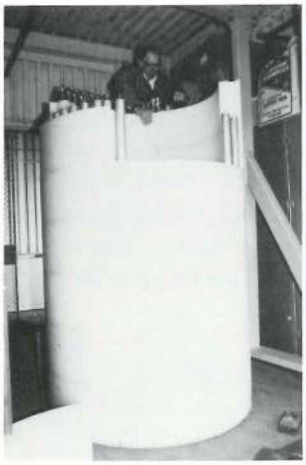
Transuranic Assay by Neutron Detection

A direct assay system developed by Battelle, Pacific Northwest Laboratories determines the transuranic (TRU) isotope content of LLW by detecting neutrons emitted from the waste.

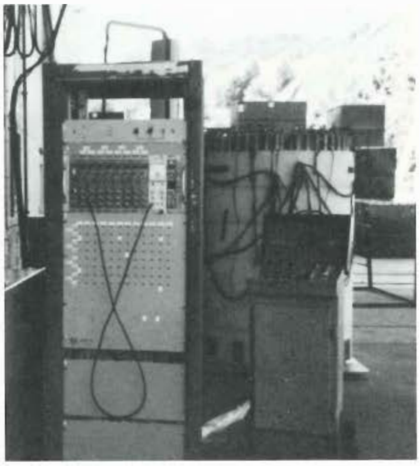
The detection system consists of an array of 96 tubes filled with boron trifluoride ($^{10}BF_3$), which surround a waste container and are connected to electronic instruments that record the neutron count and translate it to TRU radionuclide distributions. Neutrons emanating from a container are slowed by moderator material before passing into the $^{10}BF_3$ tubes, where they convert molecules of boron-10 to charged ions of lithium-7. This registers as a slight electrical charge and is recorded as data for collection and analysis.



For typical measurement of a 55-gal drum of dry LLW, the container is centered within the tube array and counted for approximately 10 min. A submersible model of the detector has also been developed for TRU assay of irradiated in-core hardware stored in spent-fuel pools.


Setup of TRU detector assembly.


Closing detector assembly around radwaste drum.


Electronic instrumentation for TRU detector.

estimated concentrations of non-gamma-emitting isotopes as well.

Teaming up at Crystal River

Neither of the direct-assay techniques individually is able to measure and quantify all the LLW radionuclides specified for analysis under current NRC rules, but EPRI recognized that if they were used in combination, along with plant-specific scaling factors, an accurate inventory could be obtained for the full spectrum of isotopes. In late 1985 EPRI and Florida Power cosponsored a project with Battelle and SAIC to demonstrate the TRU and gamma-detectors as a team at the Crystal River plant as part of a broader research project to evaluate direct measurement technologies for accuracy, practicality, cost, and conformance with ALARA guidelines.

The principal focus at Crystal River was the characterization of irradiated in-core hardware that was submerged in the spent-fuel pool, but other types of LLW—packages containing primary coolant system filters and resins and compacted dry active waste—were also assayed. About 7 ft^3 (0.19 m^3) of irradiated hardware (including the cannisters) were measured.

The submersible model of Battelle's TRU detector was used in conjunction with an intrinsic germanium detector and dose profile measurements from a series of thermoluminescent dosimeters placed every 4 in (10 cm) along the length of the storage cannisters. SAIC's QuantiScan spectroscopic gamma-detector and a RO-7 remote teleprobe measured the activity from the same cannisters separately.

Results of the TRU assay system indicated transuranic concentrations in the cannisters ranging 2–16 nCi/g—well below the Class C LLW limit of 100 nCi/g. Subsequent scrape and fragment samples of some low-dose components were analyzed radiochemically for comparison, with results about a factor of 10 below the TRU direct assay results.

"There was some difficulty comparing these results because the radiochemistry was based on a very small sample and it was not known whether the transuranics on the surface of the samples were uniform across all the hardware in the cannisters," explains Galen Clymer, Florida Power's acting manager for nuclear waste. "But it is nonetheless clear from both results that the waste was not above the Class C limit for TRU content. Even with the uncertainty, the results obtained are more accurate than those obtained by relying solely on computer-generated and dose-to-curie correlations."

For the gamma assays, results from the observed dose profile and QuantiScan methods were in reasonable agreement for the total curies of cobalt-60 in each cannister. When compared with conventional computer code–based calculation methods, the direct assay techniques gave results at least 50% lower.

Economic benefits of the direct-assay techniques were estimated on the basis of known curie surcharges at waste disposal sites. The conservative calculation methods the utility would have been forced to rely on in the absence of direct assay would have resulted in unnecessary additional disposal costs of about $50,000. EPRI project managers are working with Florida Power and the contractors to further analyze the potential cost savings of direct assay and to estimate generic economic benefits to the industry of both the TRU and gamma-scanning techniques.

Although potential savings are not yet fully quantified, participants in the demonstration at Crystal River were convinced that the increased confidence afforded by the direct assay methods yields obvious benefits. "Both the TRU and gamma-scanning methods allowed us to identify on-site what the isotopic distributions and the activity levels were, rather than relying on calculations and off-site analysis alone," says Clymer. "In typical use, they will also reduce personnel radiation exposure. Because we've proved that the lower curie measurements are in fact more accurate, the cost benefits are clear."

New tools for LLW assay

Soon both the TRU and gamma-scanning techniques may be available to the utility industry for more-accurate analysis of the full spectrum of radioactive isotopes than has been possible before. The methods promise not only to revolutionize the technical means for compliance with federal LLW regulations but also to reduce personnel radiation exposure and disposal costs, as well as lead to more-effective use of existing disposal site capacity because the true radionuclide concentrations in waste are better known.

"We expect these tools to become important options for complying with federal analysis and reporting requirements," notes Charles Welty, an EPRI program manager. "The more accurately utilities can determine what is in LLW, the more apparent these benefits will be." ■

Further reading

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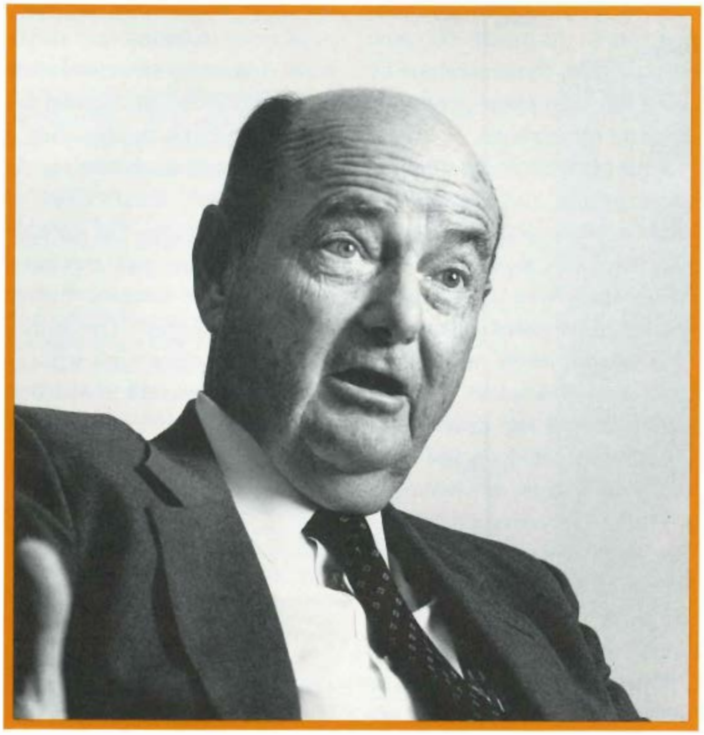
This article was written by Taylor Moore. Technical background information was provided by Patricia Robinson and Charles Welty, Nuclear Power Division.

PROFILE

Herbert Woodson



Encouraging Exploration in Research

After 32 years as an electrical engineering professor, Herbert Woodson has an understandable first loyalty to fundamental research, but committees, consulting, and advisory connections—including EPRI's Advisory Council—keep him in touch with the practical end of the electricity business.

Herbert Woodson's long suit is electrical engineering. He has three degrees from the Massachusetts Institute of Technology, teaches at the University of Texas at Austin, runs an energy research center there, and often consults with electric utilities. How does he happen to be on EPRI's Advisory Council, which specifically comprises men and women from outside the electric utility business?

The answer is that he is most of all an educator—a professor and researcher since 1954, first at MIT (17 years), then at Texas (15 years), where he has also been a department chairman (10 years) and a faculty recruiter (constantly).

Woodson's broad and deep experience in the academic world makes for a comfortable fit with his 20-plus Advisory Council colleagues, whose interests and expertise include civil rights, commerce, economics, labor, manufacturing, medicine, publishing, science, and utility regulation. Together, the Council members bring a valuable range of viewpoints to bear on EPRI's management and its view of R&D purposes and priorities.

Woodson has a clear personal dedication to energy R&D, and along the way he has found time to administer several grant-seeded, special-purpose R&D centers on the Texas campus. The principal one is the Center for Energy Studies, which he established a dozen years ago and has directed ever since. Born of the energy crisis, it is described as "a multidisciplinary research center, the central liaison for energy research, education, and public service at the University of Texas at Austin."

Inquisitive on his own, as well as on behalf of his graduate students, Woodson has never cared whether his research was on magnetic amplifiers, superconducting windings, flywheels, pulsed-power supplies, 765-kV transmission, or plasma torches. Thus, except for an easy affection that began when he worked briefly for American Electric Power Service Co. 20 years ago, the utility industry is not the focus for Woodson. His mind and his imagination are on the science itself—especially on electrical phenomena, and even more on the processes and apparatus that can make for better, cheaper, faster products and services.

Woodson converses easily and good-naturedly, but the twinkle in his eye is just as often a hard glint. He also talks clearly and straightforwardly, and with determination. "Let me get on a soapbox here," he'll say, and his conviction quickly becomes evident. But he is simultaneously enthusiastic about and detached from his interests, rewarded more by the quest than by the conquest.

Woodson is and does so much because of an endlessly inquisitive and busy nature. His personal energy is symbolic as well as essential to his career. He is a committed person, although he puts a different twist on the word with the observation, "I'm overcommitted! I'm sometimes surprised that the dean doesn't change the locks on the doors while I'm gone."

Woodson's bouncy, vibrant style surely had something to do with his coming to Texas in 1971. As he describes it, the style of the university mirrored his own. "The dean was new, and he wanted to move the engineering school up in the national rankings. Everybody was happy and smiling, wanting to get something done, and Texas had the resources to do it. They asked me to be chairman of the electrical engineering department. The more I looked at it, the more it seemed like a golden opportunity to have a major impact on a program."

What does Woodson mean by impact? "Recruiting and retaining good faculty; that's the soul of an educational institution. You need to keep them professionally happy, too—good equipment in the labs, good parking places! Then, of course, you want good students, and this means making sure that your opportunities are known to the kind of students you want."

Fifteen years later he is still at it. As head of a committee responsible for eight endowed chairs in electrical engineering, he continues to look for good faculty. He has a number of graduate students doing research, and he teaches at least one course per semester—"required undergraduate classes when I can; I really enjoy that."

But he stepped down as department chairman after 10 years. "I'm more valuable today as ex-chairman," he says with wry modesty, "because now I can talk to the dean about department needs in a way that would have been self-serving when I was chairman."

Energy for research growth

The common thread of Woodson's years at Texas is energy, and more than simply his own. The 1973 energy crisis, for example, motivated establishment of the Center for Energy Studies. As Woodson remembers it, several Texas faculty members had already organized a monthly discussion group on energy issues, and the university president put before them the concept of a universitywide bureau of energy. Shortly thereafter, he gave it the green light, earmarked $1 million for a four-year startup, and asked Woodson to establish and direct it.

"It's gone up and down," Woodson says candidly. "We've never tried to become a big contract research activity. We've worked with faculty and students and department labs; we didn't have any labs of our own until we moved into a new facility just last summer. We find someone with a good idea, and we fund him until he's to the point of getting outside support."

As an example, Woodson cites current research that EPRI helped develop. "The work is for the chemical industry, in separations processes—you know, distillations, supercritical extractions, the use of membranes. One major performance improvement would be better energy efficiency, and that's why we got involved. We put in the seed money and hired a couple of chemical engineers to help the faculty get things started.

"Now the program is in its third year," Woodson goes on, "with 40 participants at the moment—EPRI among them—at $20,000–$50,000 each. They're all on an advisory committee, so they have first call on the results and," the professor concludes with a smile, "on the graduate students."

Woodson is convinced that various industrial processes could be improved by fundamental work. He thinks especially of new electrochemical paths from iron ore to steel or from sand to semiconductor-grade silicon. "It would surely be significant if we could make the silicon metal for solar photovoltaic cells less expensively."

The distinction between research and development is sometimes blurred in Woodson's account of his center's work. Especially for defined end-use applications of electricity, what constitutes fundamental exploration? "I think there ought to be more just fiddlin' around with things," Woodson replies. "A plasma torch, for example. There ought to be opportunity to run stuff through it and see what happens. Try it in different ways with different chemicals and see what it can do physically and chemically."

Woodson explains that a plasma torch is an electrical means of heating a gas to a much higher temperature than is possible by combustion. Chemical reactions in the hot gas, the plasma, proceed much faster. Some reactions do not even occur at lower temperatures, so there is an opportunity for totally new processes.

"Take plasma spray coatings, for example. If you get aluminum oxide hot enough," he continues, "and you spray it hard enough, it will stick on a surface as a hard coating that's a good insulator, resistant to corrosion and effective at fairly high ambient temperatures."

Woodson is on a soapbox now, caught up by the possibilities for new and more-productive end uses of electricity. "For the immediate future I have the feeling that we will do ourselves, our economy, more good by looking at the consumption side of the energy equation than at the production side. We've got plenty of capacity. We need to use electricity in innovative ways that will improve our competitive position in the world."

Even when he is consulting, chances are that Woodson is teaching. In recent years he has worked with a number of utilities (Central Power and Light Co., Gulf States Utilities Co., Houston Lighting & Power Co., and Texas Utilities Co.) but he calls attention to his advisory role on nuclear power projects.

"We will do ourselves, our economy, more good by looking at the consumption side of the energy equation than at the production side. We need to use electricity in innovative ways that will improve our competitive position in the world."

"At Gulf States, for example, there are three of us, all university professors, on a nuclear safety advisory committee. Tom Pigford is chairman of nuclear engineering at the University of California, and Ned Lambremont, a radiation biologist, directs the nuclear science center at Louisiana State. It's really a technical auditing activity. We meet four times a year and hold the engineers' feet to the fire, so to speak, to make sure that the engineering work has a sound technical basis."

Woodson describes a series of oral examinations that have evolved. At first, they were bland recitals of work schedules, procedural steps, and compliance memoranda. Now, at the committee's insistence, they are lively exchanges on the physics and thermodynamics of plant processes. "We want to hear about the equipment they've designed and their assessment of how well it works. We give them a technical quiz on what they're doing. If someone cites a commonly used factor, we ask him to derive it from first principles."

The class is getting good marks, according to Woodson. "It's come to where they relish having to make presentations to the professors. We didn't realize we were doing that much good, but management is so pleased with the heightened technical awareness that we're still doing it—ever since 1980."

Woodson's account of similar advisory work for Houston Lighting & Power emphasizes his affection for utilities. "Whenever a utility asks me to do something I'm qualified to do, I really try to do it." And after thinking for a moment, he pointedly adds, "I feel that nuclear is really the finest power generation technology we have right now. If we don't botch it up, it can be our least expensive, least intrusive, and safest source of baseload electricity; and I'd like to do what I can to make that so."

The electric connections

Although Woodson's professional career has unfolded in an orderly way, there has been a good bit of coincidence and serendipity involved. The important point is that he took advantage of opportunities, beginning when he graduated from high school in Lubbock, Texas, at the age of 17.

That was in 1942, and the opportunity was the U.S. Navy. Woodson had only months in which to decide; at 18 he would be subject to the military draft, with no choice of service branch and few special training opportunities. He enlisted in the navy and gambled on passing the examination for radio technician school.

It was a good gamble. He passed, finished second in a class of 250, sailed a quarter-million miles on a troop transport, and then decided to study electrical engineering at Texas Tech University, back in Lubbock, after the war. But a perceptive navy counselor at the separation center had other ideas. Picking up where Woodson's navy travel left off, he painted a future of wide academic horizons and high career goals and handed Woodson an MIT catalog.

The reminiscence warms Woodson. "I was stunned, because I'd not been an excellent student. But I read the catalog, took the college board exam, applied, and was admitted. I went to Cambridge in 1947 as a 22-year old freshman on the GI Bill, and I stayed for 24 years."

That outcome was another instance of serendipity. "As a doctoral student in 1956 I helped my thesis adviser compile notes for an undergraduate text in rotating machinery—my specialty—and he asked me to stay around, help him turn the notes into a book, and be coauthor. So I did. I never intended to be a faculty member, but that was the initial reason I stayed on. Oh, yes, the book was published in 1959."

Woodson recalls another person who was important to his increasing activity in electric power. This was was Philip Sporn, chief executive officer of American Electric Power Co. and a living legend in the utility industry. Sporn was on the MIT electrical engineering visiting committee when Woodson met him and began to learn what the power business had to offer. In part because Sporn wanted to encourage power engineering education at MIT, Woodson spent a sabbatical year, 1965–1966, as a staff electrical engineer at AEP Service Corp., Sporn's engineering subsidiary. Returning to MIT, Woodson became the Philip Sporn Professor of Energy Processing.

Other professional activities in power engineering engaged Woodson in the late 1960s. Memberships on the rotating machinery and education committees of the IEEE Power Engineering Society (both of which continue today) are examples that come to mind. Also, he worked for the research division of the Edison Electric Institute, and he served on an American National Standards Institute Committee on generators. These set the stage for his being retained in 1971 by the utility industry's Electric Research Council to work with its newly organized R&D Goals Task Force as a consultant.

EPRI was built on the report of that task force, which identified a 30-year R&D agenda for utilities, put a price on it, and concluded that a centralized venture was the way to go. "If you look in the green book they put out," Woodson states, "you'll find that I was their one technical consultant. I went to all their meetings and helped them write their report."

Asked what he did that the task force members could not have done as well, Woodson searches for the right phrase. "I helped them with the more fundamental scientific side, I think. We were all engineers, but I had an overlap into the research community, whereas theirs was into utility operations. I was the one in the middle."

Also in the early 1970s, Woodson served briefly on a committee for the White House Office of Science and Technology. He thereby met the assistant director for energy, environment, and natural resources, Richard Balzhiser, who was shortly to join EPRI and become its senior vice president for R&D. But before doing so, Balzhiser organized and led a 10-day trip to the USSR for Woodson and 16 others, furthering a periodic scientific and technical interchange. The State Department officer for the group was Robert Loftness, who would later be director of EPRI's Washington Office and secretary of the Advisory Council.

The chain of coincidence and serendipity in Woodson's professional career culminated in 1984 when Loftness telephoned Woodson and invited him to join the Advisory Council. The council chairman at the time was David White, director of MIT's Energy Laboratory, Woodson's doctoral thesis adviser and coauthor of 28 years earlier.

"I was impressed by how thoroughly the whole advisory apparatus of committees and task forces deals with EPRI's program. It wasn't just a superficial approval of what the staff put up; they got down to brass tacks."

The adviser learns

Not exactly an outsider to the utility industry, Woodson acknowledges, "I have to remind myself that the Council isn't a bunch of utility people worrying about how to get a utility engineering job done. But I've learned a good bit, especially about what's going on at EPRI."

For example, he recalls representing the Council at a meeting of the Research Advisory Committee (RAC), the senior technical resource drawn from EPRI's membership. "That was illuminating. I was impressed by how thoroughly the whole advisory apparatus of committees and task forces deals with the program. It wasn't just a superficial approval of what the staff put up; they got down to brass tacks."

Woodson also mentions the evident knowledge and insight of the utility regulators who hold Advisory Council membership. Like many people, Woodson had a different preconception from reading news accounts of regulatory controversies in various states. In his own state of Texas, for example, the utility commission is a fairly new government body, but in Woodson's view it has been politicized by a recent round of appointments.

For Woodson, the EPRI regulator-advisers at first seemed too good to be true. (Seven state utility regulators are named to the Advisory Council by their professional body, the National Association of Regulatory Utility Commissioners.) "I still suspect they aren't typical," Woodson says. "They're much more understanding of the utility industry than I thought they would be."

But it is on his pet subject of electricity end use that Woodson finds real opportunity with the Advisory Council. Examination of EPRI's end-use R&D program, in fact, was the charge of a five-member council subcommittee on which he served last year. The group conferred with EPRI's Energy Management and Utilization Division, took on its own literature research and writing assignments, discussed and edited its findings, and delivered its report last December. With some revision, it was adopted by the council and directed to Floyd Culler, EPRI's president, for response.

The report takes an aggressive view. Technology, economics, and public policy are widening the range of choice for energy users, it points out, so electric utilities must compete in new ways. "EPRI's objectives should be shaped by a market-driven objective of increasing consumer choice."

Woodson and his colleagues affirmed EPRI's recent action to consolidate its analytic and technical research in end uses. In fact, they went on to urge that such research be elevated to EPRI division status within three years, and they further called for this new division to command about a third (20–40%) of EPRI's annual R&D budget within five years, up from the current 8%. Further, the subcommittee report endorses an improved competitive stance for U.S. industry as a proper goal for EPRI "because the health of the utility industry is closely linked to the health of the economy as a whole."

Woodson sees distinct benefits from R&D that is statedly inclusive, that encompasses and integrates the interests of consumers along with those of utilities. He mounts his soapbox to make clear how easily utilities can justify R&D for the betterment of other industries. "EPRI's work may even improve an industrial process without using more electricity," he begins, "but if that increases the level of industrial activity and makes us more competitive in the world, then it will indirectly benefit a lot of other workers, too, and all the people they do business with." The clincher comes when Woodson observes, "And everyone involved in that heightened industrial activity lives in a house that uses electricity."

"The way to do fundamental research is to identify some talented researchers in an area of interest, give them three years of funding, and tell them, 'Go do what you think best—just add to the store of information.'"

The tension between R and D

Another recommendation by the Advisory Council subcommittee called for devoting a fixed percentage of end-use research funding to exploratory research—adding to the fundamental knowledge base in relevant scientific areas. Noting the different kind of professional experience needed, the subcommittee also urged that EPRI reconsider an early plan to manage all its basic research as a separate division. Both these points call attention to the difference, the tension, sometimes the conflict between fundamental and applied research practice.

This tension draws Woodson's interest, and he is concerned with more than end-use R&D alone. "I think EPRI is probably best qualified to do applied work—that is, in terms of the staff it has. Look at the Cool Water project, integrating coal gasification and combined-cycle generation and demonstrating them at 100-MW scale.

"But I think EPRI overplans a bit," Woodson adds. As he sees it, this is mostly a matter of a useful professional quality being carried too far, "but there's sometimes an unfortunate rigidity too. I've known some EPRI managers to have a very narrow view of what needs to be done. They've gone through their planning exercise and they seem to say, 'We've settled on this and we aren't looking for anything new. If it isn't in our plan, then it's not a good idea.' Ideas have been dismissed out of hand that way," Woodson insists.

The words warn of an attitude that can threaten the value and the course of applied research. But excessively detailed planning bothers Woodson mainly because it can stifle what is intended to be basic research. He elaborates this way. "If I contract with you to deliver a specified item in a specified time on a specified budget, that's not research. That's development, at best; maybe it's just production. Research means exploring the unknown.

"You can sit down and think logically about where you're going and how you're going to get there. But the probability is that the real advances will be nothing you predicted." The scientific and technical literature of 25 or 50 years ago makes Woodson's point. "We're not doing today, technologically, what the experts of those days predicted. But have there been advances? You bet! Tremendous advances, but not what people expected."

From his long university experience Woodson insists, "The way to do fundamental research is to identify some talented researchers in an area of interest, give them three years of funding, and tell them, 'Go do what you think best—just add to the store of information.'

"Three years later, you ask what they found out. If they learned something really significant, you fund them again. If not, you don't."

Woodson relaxes a bit and admits that an orderly process is needed for guiding either basic or applied research. He mentions a framework—a decision matrix—for setting priorities, making either/or decisions, and measuring results. "It's just that I think there's a tendency to overdo it," he concludes somewhat wistfully.

Woodson also argues for a better balance between near-term applied research and exploratory, probably long-term, research. "Fundamental research generally is fairly inexpensive," he points out, "so you're able to take multiple paths to begin with. You take ten paths, and when one of them is fruitful, you can be happy and not worry that the others led nowhere."

But what appears to be a 90% failure rate is difficult for some scientists (and certainly for many engineers) to deal with. Woodson remembers urging his image of research management with the Electric Research Council task force 14 or 15 years ago, but without success. What stood in the way? Momentarily silent, he then admits he is picking his words carefully.

"I think it was a matter of belief or, the other way around, of disbelief. A great number of the leading technical people in utilities, including CEOs, didn't easily think of R&D as a force that could be productive on a real-time basis. They weren't hostile to it; they just didn't believe in it as a way to do things more economically or efficiently during their own working years."

This view of R&D was and is totally sincere, Woodson points out, and common among CEOs who come from the planning, financial, or legal side of the business today. But its paternalistic quality is revealed by Woodson's figure of speech. "They fund R&D with what they think it deserves," he says. "It's like your feeling about a child's allowance: you want to give what is appropriate, but you don't want to give too much."

The adviser advises

Touching again on the way power research is organized and managed, Woodson believes that in some key areas EPRI would do well to establish and operate its own research facilities with its own research staff. "I think it's difficult to maintain your competitive edge without having more than a monitoring role in research. I think some of the EPRI staff would be sharper if they were directly involved in it."

Warming to the idea, he begins to see it in fairly focused terms, "a lab dedicated to a particular area of technology, say, turbine generators. This year the research focus is bearings; next year it's shafts; and after that it could be stator insulation or stator cooling. It could move with the needs of the times."

Reflecting on the number of opinions he has offered, mindful of the price tags on many of his ideas, and perhaps feeling he has been shooting from the hip (a true Texan), Woodson is nonetheless a man of convictions when it comes to electric power R&D. From his soapbox he surveys a wide field of opportunity and need.

"I think EPRI ought to be funded somewhere between three and six times as much as it is now. Industries that flourish put a sizable fraction of their incomes into research, on the order of 5% or so. And once it's up and running, research is the continuous source of new things that keep the industry flourishing."

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Woodson declares that R&D is a trivial part of any customer's electric bill today, "peanuts!" Even so, he lowers his sights a little as he continues. "EPRI's budget could at least be doubled or tripled, with the full consent of regulators, I believe, if the utility executives really believed in it."

After more than 30 years in electrical engineering education and in close cooperation with the utility industry, Woodson sees the need in such simple terms because the subject itself is so complex. "An electric utility is technologically a very complex system," he declares, "a hell of a lot more complicated than a space shuttle. Anything that complicated, in my view, is worthy of R&D attention to make sure the technology is continually serviced and improved. You need to pay attention to its needs." ■

This article was written by Ralph Whitaker and is based on an interview with Herbert Woodson.

Board Approves 1986 Budget Revision

The number of EPRI member utilities continues to grow as revenues decrease slightly.

EPRI's Board of Directors, at its April 9 meeting in Washington, D.C., approved a revised 1986 overall budget of $311 million, which includes an R&D portion that totals $287 million.

Board Chairman Arthur Hauspurg reported that EPRI membership continues to grow and now exceeds 600 utilities. A slight decline in 1986 revenues from 1985 levels was attributed by Hauspurg to financial pressures facing a few of EPRI's larger member utilities as a result of nuclear plant construction programs or weak regional economies. "Most of these companies report that they expect recovery in the near future," he said.

Responding to the revised budget, EPRI President Floyd Culler announced several measures to reduce administrative and support expenditures. As approved by the Board, these measures include the cancelation of executive salary increases for 1986 and some reduction and delay of other employee merit raises. In addition, the total number of authorized positions at the Institute will be reduced by 5% over the next 12 months, primarily through attrition and retirements. Culler also commented that expenditures for travel and capital equipment will be lowered.

Hauspurg called this response a "balanced and responsible management approach to what we expect will be a short-term problem." Despite the funding decrease, Culler emphasized that the Institute's budget still provides for a vital industrywide R&D program. "At a time when government and private funds for energy R&D continue to decline," he said, "EPRI's work is all the more important for the national interest." ■

New Board Members Elected

The EPRI Board of Directors was expanded from 15 to 24 members, and new directors were elected at the Board's April meeting. New appointments to the Advisory Council were also announced at the meeting.

The newly elected directors are Howard P. Allen, chairman and CEO, Southern California Edison Co.; Wilson K. Cadman, chairman and president, Kansas Gas and Electric Co.; A. W. Dahlberg, president and CEO, Southern Co. Services, Inc.; Jerry D. Geist, chairman and president, Public Service Co. of New Mexico; Girts Krumins, president, Colorado-Ute Electric Association, Inc.; Donald W. McCarthy, chairman and CEO, Northern States Power Co.; Norman E. Nichols, assistant general manager for power, Los Angeles Dept. of Water & Power; Larry W. Papasan, president and CEO, Memphis Light, Gas & Water Division; Bernard W. Reznicek, president and CEO, Omaha Public Power District; and Stephen J. Sweeney, president and CEO, Boston Edison Co. Robert N. Cleveland, president, Buckeye Power, Inc., was reelected to the Board.

Peter A. Bradford, chairman, Maine Public Utilities Commission, was appointed to the Advisory Council, and three members were reappointed: Edward F. Burke, chairman, Rhode Island Public Utilities Commission; Edward P. Larkin, commissioner, New York Public Service Commission; and Andrew Varley, chairman, Iowa State Commerce Commission. ■

R&D Program Funding Levels Set

The following 1986 R&D funding levels were approved for EPRI's technical divisions by the Board of Directors at its April meeting: Coal Combustion Systems Division, $63.2 million; Nuclear Power Division, $52.1 million; Electrical Systems Division, $36.6 million; Energy Management and Utilization Division, $31.1 million; Energy Analysis and Environment Division, $29.2 million; and Advanced Power Systems Division, $20.4 million.

In addition, 1986 total expenditures were approved for six separately funded programs: Steam Generator Owners Group Program II, $7.6 million; BWR Owners Group Intergranular Stress Corrosion Cracking Research Program II, $3.2 million; Utility Acid Precipitation Study Program, $0.8 million; Hydrogen Control Program, $0.6 million; Nuclear Fuel Industry Research Program, $0.5 million; and Seismicity Program, $0.5 million.

Total authorized funding was increased for five other programs to the following approximate levels: PWR Steam Generator Reliability, $30 million; Robot Applications for Nuclear Power Plants, $8.5 million; Amorphous Metal Power Transformer, $7.4 million; Turbine Blade Life Improvement, $6.2 million; and Aging of Extruded Dielectric Power Cables, $6.2 million. ■

CALENDAR

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

JUNE

24–26
Seminar: Transmission Line Design Optimization
Schenectady, New York
Contact: Richard Kennon (415) 855-2311

JULY

9–10
EPRI's Transient/Midterm Stability Computer Program
Toronto, Canada
Contact: John Lamont (415) 855-2832

9–10
Workshop: Water Hammer in Nuclear Plants
Boston, Massachusetts
Contact: Jong Kim (415) 855-2671

16
Seminar: Instream Flow Methodologies
Seattle, Washington
Contact: Edward Altouney (415) 855-2626

AUGUST

13–14
Software Integration for Power Systems Analysis
Washington, D.C.
Contact: John Lamont (415) 855-2832

25–27
Nuclear Plant Life Extension Studies
Alexandria, Virginia
Contact: Melvin Lapides (415) 855-2063

27–28
Software Integration for Power Systems Analysis
Seattle, Washington
Contact: John Lamont (415) 855-2832

SEPTEMBER

3–5
Workshop: Technology Transfer
Fort Worth, Texas
Contact: Conway Chan (415) 855-2099

9–11
Seminar: Plant Inspection
San Antonio, Texas
Contact: John Scheibel (415) 855-2850

9–11
Workshop and Seminar: Bearing and Rotor Dynamics
St. Louis, Missouri
Contact: Stanley Pace (415) 855-2826

17–19
International Utility Symposium: Health Effects of Electric and Magnetic Fields
Toronto, Canada
Contact: Robert Patterson (415) 855-2581

22–25
Seminar: Partial-Discharge Testing and Radio-Frequency Monitoring of Generator Insulation
Toronto, Canada
Contact: James Edmonds (415) 855-2291

23–26
Workshop: Gas Turbine Procurement and Repowering
Pittsburgh, Pennsylvania
Contact: Henry Schreiber (415) 855-2505

24–25
Industrial Applications of Adjustable-Speed Drives
Washington, D.C.
Contact: Marek Samotyj (415) 855-2980

OCTOBER

7–9
1986 Fuel Oil Utilization Workshop
Philadelphia, Pennsylvania
Contact: William Rovesti (415) 855-2519

14
Seminar: Coal Transportation Costing and Modeling
San Diego, California
Contact: Edward Altouney (415) 855-2626

14–16
Seminar: Solid-Waste Environmental Studies Technology Transfer
Milwaukee, Wisconsin
Contact: Ishwar Murarka (415) 855-2150

15–16
6th Annual EPRI Contractors' Conference on Coal Gasification
Palo Alto, California
Contact: Neville Holt (415) 855-2503

Getting People Involved: PSI's Key to Tech Transfer

According to David Odor, a research coordinator for Public Service Co. of Indiana (PSI), "EPRI is doing a super job, but technology transfer is a two-way street, and the utility should take the initiative." PSI has taken this philosophy to heart and has developed an integrated technology transfer program that works with only minimal maintenance. The successful program turns on two key points: a bottom-up approach that stresses PSI staff involvement and an easily accessible data base used to track EPRI work in PSI target areas.

The bottom-up approach, a cornerstone of the effort, was built into the program from the very beginning. PSI's Research Department conducted a survey and staff interviews to establish the initial level of technology transfer within the utility. Armed with that information, PSI identified EPRI research projects that matched the utility's application priorities. Information on each of these projects was condensed and made available on a utility data base accessible throughout the company. *EPRI Journal* R&D status reports on PSI priority projects have also been condensed to one or two pages and matched with staff interest areas.

With this system the utility aims to identify PSI–EPRI priority projects at the earliest point, to track their progress, and then to apply the research results. PSI staff members can routinely access the system to obtain relevant EPRI information from the data base as it is needed. The information stored in the data base has also been an essential element of the four benefit assessment studies conducted by PSI since 1983.

PSI combines all its available resources to effectively promote technology transfer and to involve people within the utility. Members of the PSI–EPRI Advisory Committee serve as industry advisers on EPRI committees, and within PSI they provide guidance on utility research objectives and disseminate information on EPRI's structure, funding, programs, and personnel. In addition, PSI staff members help identify the EPRI research projects that will match corporate priorities.

Company needs can quickly and easily be matched with staff resources by using information from the Technical Interest Profile (TIP) system, the PSI distribution list for the condensed R&D status reports, and the PSI library distribution list for final reports on PSI–EPRI priority projects. Stored in the PSI computer system, the TIP records are used to distribute EPRI seminar announcements in addition to the 1500 EPRI report summaries that are distributed monthly to over 100 PSI employees. Care is also taken to track reassigned employees within the utility and to ensure that all data bases contain the correct information.

The effectiveness of a utility's technology transfer depends on a good, well-executed plan rather than on enormous resources. It takes only three professional staff members and one clerk in the Research Department to develop and implement this technology transfer program, even though PSI, with 4000 employees, is the largest investor-owned utility in the state. Janie Farrington, the research clerk, is a key ingredient to the success of the PSI program. According to her, "Technology transfer is more than data and reports—the exciting, and possibly critical, part is interacting with people and responding to issues that impact company needs." Because of automation she now spends only 25% of her time keeping the program running smoothly.

One result of this program is the PSI staff's familiarity with EPRI and its research products. Farrington describes the EPRI resources and the availability of information in presentations made to PSI personnel in power plants and field offices. In addition, EPRI videotapes are presented at widely advertised luncheon programs, and copies are distributed throughout the company.

As the PSI staff is more aware of EPRI's value as a resource, it increasingly turns to EPRI with technical problems. In 1984, for example, station personnel noted that the Gibson No. 5 chimney liner appeared to have shifted. Ronald Richard, the chemical superintendent at Gibson station, contacted Dorothy Stewart, a project manager in the EPRI Desulfurization Processes Program, and one week later EPRI and its contractors were on site to evaluate the situation and to help establish operating guidelines until the problem could be solved.

Asked what suggestions he would make to other utilities considering a similar technology transfer program, Thomas McCafferty, PSI's research manager, emphasizes that they should "pick a staff with a broad understanding of the utility's internal organization. Then give each member the freedom to go from department to department and the charge to get people involved." After all, he reasons, "if the company were going to start work on a power plant project costing millions of dollars, it would make a long-term assignment of a top-notch team to see that the job was done right. Technology transfer deserves no less." ■

Indicator Available for Stability Limits

Power plant control room operators can now avoid a unit trip by using a new electronic instrument that provides a clear indication of the approach to the generator's stability limit. This new device, the power angle instrument for large synchronous machines, has been produced for commercial use by Eumac, Inc. The instrument operates by taking the armature voltage zero crossing as a reference point and relating an electrical signal derived from the rotor position to that reference point. Using a magnetic pickup and a toothed wheel on the shaft, the device provides digital and analog readouts of the voltage proportional to the angular difference between signals.

EPRI licensee: Eumac, Inc., 221 W. Surrey Avenue, Phoenix, Arizona 85029. ■ *EPRI Contact: Dharmendra Sharma (415) 855-2302*

Guidelines for Controlling Corrosion-Causing Products

Austenitic stainless steels or nickel-base steels used in nuclear power plant components are subject to stress corrosion cracking or intergranular attack when placed in contact with materials or chemicals containing certain contaminants. Steels can be inadvertently damaged by expendable materials or chemicals, such as lubricants, solvents, tapes, and nondestructive evaluation substances. Although no harm will result if concentrations are kept at safe levels, there have until recently been no standard industrywide practices.

After reviewing the wide variety of current practices, EPRI saw the need to create a recommended program for the industry, incorporating the most effective industry practices. *Guidelines for Control of Expendable Products* (EPRI NP-4449) is now available to help utilities develop such a program to identify and control the contacts between contaminants and the vulnerable steels in nuclear power plants.

Written in a clear, easy-to-read style, the recommended program identifies the contaminants, specifies their maximum safe concentrations, and describes test methods for determining contaminant levels in each batch or lot of a product. In addition, the program provides a model for a procurement specification, a justification of acceptable contaminant levels, and a sample product list. Utilities can use this document to evaluate their current practices and develop a more comprehensive program for expendable product control. ■ *EPRI Contact: John Carey (415) 855-2105*

Manual for Rating Cable Terminations

Until recently, emergency ratings of cable terminations in high-voltage underground transmission systems were often inaccurate because they were based on limited testing supported by experience. A new manual, *Emergency Ratings of Cable Terminations* (EPRI EL-4293), now provides two computerized methods to calculate these ratings—a network procedure and a matrix procedure—as well as emergency rating tables. Besides helping transmission system designers and operators provide maximum safe operation during emergencies, these methods can be used to eliminate overdesign and unnecessary conservatism in planning and operating utility systems.

Quick and easy to use, the network procedure produces acceptable ratings with a minimum of time and effort. The matrix procedure requires more computer time and is more complicated to use, but it produces more accurate ratings. When time is truly of the essence, the manual's rating tables can provide utility personnel with an emergency rating immediately. Applicable to all widely used cable sizes and voltages under typical operating conditions and termination environments, the tables provide a quick estimate, saving time and eliminating the need to have an experienced computer programmer available. Although the tables do not include ratings for forced-cooled pipe-type cable systems, these can be calculated by using the computerized methods described in the manual. ■ *EPRI Contact: John Shimshock (412) 722-5781*

R&D Status Report
ADVANCED POWER SYSTEMS DIVISION

Dwain Spencer, Vice President

LINE-CONNECTED PHOTOVOLTAIC SYSTEMS

Photovoltaic (PV) power plants, which convert sunlight to electricity, may offer utilities a variety of advantages as potential bulk power sources: they emit no pollutants, they are modular, they can be constructed quickly, and they are highly reliable. Although PV costs are still too high for bulk power applications, they have dropped dramatically in the past decade and will probably continue to decline. Over the past five years a number of test installations have been set up in the United States, and state-of-the-art megawatt-scale installations have gone from initial design to line-connected operation in less than a year. It has been the objective of an EPRI project to monitor and analyze the operation of representative line-connected PV systems and to track the performance of individual modules produced by different manufacturing techniques. Since the project began, 13 line-connected systems, ranging in size from 18 kW to 1000 kW, have been monitored, along with more than 20 modules from a variety of manufacturers.

Systems and modules

The PV power plants examined in this project (RP1607) were assembled from one of two major types of modules: concentrator modules or flat-plate modules. Concentrator modules must track the sun in two axes, whereas flat-plate modules can operate in either a fixed, single-axis tracking mode or in a two-axis tracking mode.

The flat-plate modules tested are further characterized by the type of material used in the cells that constitute the modules, either single-crystal or polycrystalline silicon. Single-crystal silicon is used in most concentrator modules, although data are also reported for a Varian Associates concentrator module in which single-crystal gallium arsenide cells are used. Table 1 shows the design features of the line-connected systems included in the study. Modules are composed of cells, each producing about half a volt, that are connected in series-parallel combinations. Three of the plants—the ones at Hesperia, California; Lovington, New Mexico; and Beverly, Massachusetts—are composed of separate but identical segments.

The sunlight that powers PV modules is measured in watts per square meter. Two commonly measured components of incoming solar radiation (insolation) are the direct-normal, which comes directly from the sun in parallel rays, and the global, which includes the direct-normal plus the diffuse, or indirect, insolation that is refracted and reflected from clouds, dust particles, water vapor, and the ground. Because direct-normal insolation arrives in parallel rays, it can be focused and concentrated; diffuse insolation arrives from all directions and hence cannot be concentrated.

On a clear day the total global insolation received by a surface perpendicular to the sun's rays typically is about 1000 W/m^2; the direct-normal component of that total (i.e., the component useful in concentrator modules) is about 850 W/m^2. These levels of insolation are used as the standard conditions against which PV modules are rated.

The systems examined can be distinguished by the sunniness of the location (because the power output depends on insolation) and by the operating characteristics of the equipment. The available global insolation varies substantially from one location to another and with the tracking mode employed—for example, from 3.64 kWh/m^2 average per day at Georgetown, D.C. (a fixed system), to 9.31 kWh/m^2 per day at Hesperia (a two-axis tracking system). Two of the PV sites monitored by EPRI are particularly sunny: Phoenix and Hesperia. These sites are ideal for either type

Table 1
LINE-CONNECTED PV PLANTS MONITORED IN 1984

Site	Year On-Line	Rating (kW) Manufacturer	Rating (kW) Calculated	Module Efficiency (%)	Tracking	Capacity Factor (%)[4]
Beverly, Massachusetts[1]	1981	100	94.9	5.3	Fixed	5.7
Dallas, Texas[2]	1982	27	18.7	8.3	Two-axis	19.8
El Paso, Texas[1]	1981	18	14.3	5.3	Fixed	24.9
Georgetown, D.C.[3]	1984	300	231.0	6.3	Fixed	12.0
Hesperia, California[3]	1982	1000	729.0	6.8	Two-axis	32.9
Lovington, New Mexico[1]	1981	100	88.6	5.2	Fixed	20.6
Oklahoma City, Oklahoma[3]	1982	135	78.4	5.0	Fixed	16.1
Phoenix, Arizona[2]	1982	225	151.0	6.7	Two-axis	9.8

[1]Single-crystal silicon.
[2]Concentrator.
[3]Polycrystalline silicon.
[4]Based on calculated ratings.

of module; flat-plate modules are installed at Hesperia and concentrators at Phoenix.

Table 1 also shows key performance results from the line-connected sites; the results confirm that efficiency is generally higher for single-crystal modules, for newer sites (which benefit from improvements in cell manufacturing techniques and design), and for concentrator sites (AP-2544, -3244, -3792, -4466).

Moreover, researchers find that historical test data provide a solid basis for determining how these plants respond to insolation, ambient temperature, and wind speed. Wind speed affects module cooling, and PV conversion efficiency is a function of cell temperature, being greater at lower temperatures.

Because PV systems are modular, the performance of large, megawatt-scale systems can be predicted by using data obtained from smaller systems and modules. Regression equations based on past performance predict output levels with a high degree of confidence. Evaluation of the regression equations for each site at standard conditions yields the calculated ratings (which are all lower than the manufacturers' ratings) shown in Table 1.

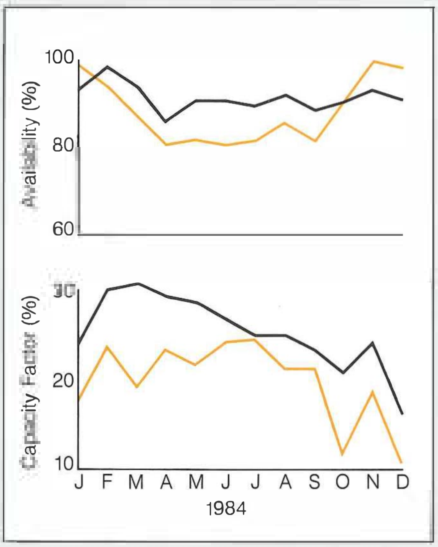
Photovoltaic modules produce dc, and all but one of the large systems monitored in this project use inverters to convert the dc to ac; only in the 18-kW system operated by the El Paso Electric Co. is dc used directly for charging batteries.

In a cooperative program with EPRI, Pacific Gas and Electric Co. (PG&E) monitored 26 PV modules over a three-year period. The results confirm those reported in the analysis of line-connected systems. Module output levels again failed to match manufacturers' ratings in most cases, but statistical data can be used in regression equations to predict with confidence what the output levels will be as a function of insolation and temperature.

The results from PG&E's fixed flat-plate test program indicate efficiencies that are higher than those shown for the line-connected systems because some of PG&E's modules were constructed by using more-advanced manufacturing techniques and because the line-connected systems incur some losses in interconnections and inverters, as well as from mismatches in currrent-voltage curves.

Differences in tracking mode also affect the amount of insolation converted to dc. PG&E found that in San Ramon, California, two-axis tracking modules receive about 34% more insolation than do fixed flat-plate modules and therefore produce about 34% more energy output. For utilities with peak loads in midafternoon, the more uniform output pattern of the two-axis tracking throughout the day suggests a greater capacity credit than can be given for

Figure 1 Dallas (color) and Lovington-1 (black) show relatively high availabilities throughout the year. However, capacity factors in Dallas peak during the summer when days are longer, but not in Lovington. In Lovington the skies are clearer during the winter (less haze and fewer clouds than in summer).



fixed flat-plate modules. PG&E checked the effect of seasonally adjusting the fixed flat-plate modules but could achieve only a 3% gain in energy output.

There is substantial variation in insolation with the seasons, as shown by the monthly capacity factor data from Dallas and Lovington-1 in Figure 1. The days are longer in June and July, and as would be expected, the insolation (and thus the capacity factor) is greatest during these months in Dallas. But at Lovington, the insolation peak occurs not in midsummer, when skies are hazy and cloudy, but in the early part of the year, when skies are more often clear.

Because lifetimes of 20 to 30 years are anticipated for PV plants, a key issue in the feasibility of using PV as a bulk-power source is whether performance will degrade over time. PG&E found 2–7% degradation in four early modules over a three-year period. No degradation was observed for most of the modules.

The performance of one of the line-connected systems did deteriorate over a period of several years because of the inverter's failure to follow the modules' peak power point, which varies with insolation and module temperature.

Concentrator modules have been based on three designs: line-focus parabolic troughs, line-focus Fresnel lens modules, and point-focus Fresnel lens modules. Although they appear to work well for collecting thermal energy, parabolic trough concentrators are unsatisfactory for PV applications, largely because of reflectivity degradation and nonuniformities in concentrated solar flux. However, both the line-focus and point-focus Fresnel modules show promise for large-scale utility applications, and EPRI monitored one of each.

Efficiency and reliability

Concentrator systems are potentially more cost-effective than crystalline silicon flat plates, not only because they require less of the high-cost crystalline silicon but also because the cells can be more efficient at high concentrations. This efficiency gain is partially offset by a decline in efficiency caused by the higher cell operating temperatures; as a result, cooling is an important aspect of concentrator design.

The line-focus system at Dallas extracts heat from the cells by pumping coolant past the cells; the heat is then used in a nearby hotel complex. Most other concentrator systems, including the one operated by Arizona Public Service Co. at Phoenix, use passive cooling, with air-cooled heat sinks mounted behind the cells.

The concentrator systems showed substantially higher efficiencies (calculated for standard conditions) than the flat-plate systems, ranging from 8.8% at Phoenix to 16.0% for a 1000 × gallium arsenide test module built by Varian and evaluated by PG&E.

The high reliability projected for PV equipment offers a major potential advantage in utility applications. PG&E noted that PV modules were more reliable than the equipment used to monitor them. Even in the larger line-conected systems there are few moving parts (none in fixed flat-plate systems), and with experience and improved designs, the actual performance has shown steady improvement.

Some problems do persist. For example, throughout 1984 and early 1985 the Phoenix site experienced a variety of component problems, including an inverter failure, a blocking-diode failure and ground fault that caused a fire, moisture inside the modules, and data acquisition system outages.

Availability, defined here as the ratio of system operational hours to the number of hours of sufficient insolation to operate the system, is a measure of equipment reliability. Figure 1 shows that system availability was always above 80% at the Dallas and Lovington-1 sites. This suggests that future PV equipment can be expected to be quite reliable, so a plant's output will depend almost exclusively on the insolation at the site and on the efficiency with which sunlight can be converted into electricity.

Because of the inherently reliable design of line-connected PV systems, their operating and maintenance costs are expected to be low. Preliminary results from plants that have passed the period of early failures and engineering changes confirm this expectation. Estimates of these costs for 1985 range from about 0.3¢/kWh for Lovington to 0.85¢/kWh for Hesperia to as much as 2.8¢/kWh at Dallas, where the circulating coolant system has required much attention. *Project Manager: John Schaefer*

USE OF LIGNITE IN TEXACO IGCC POWER PLANTS

The Texaco coal gasification process uses a controllable, high-pressure coal-water slurry transport system to feed coal to the gasifier. Because of the high equilibrium moisture content of lignite (compared with that of bituminous coal), the total amount of water in a slurry feed with lignite is undesirably high. The increased water content results in higher oxygen consumption, with an attendant increase in integrated gasification–combined-cycle (IGCC) power plant costs and a reduction in net power output. The major objective of the research described in this report is to identify and evaluate alternative methods for feeding lignite to the Texaco gasifier that would eliminate the disadvantage of carrying surplus water into the gasifier.

Table 2
STUDY CASES AND RESULTS

Case	Coal	Gasifier Feed System	Oxygen/ Coal Carbon*	Plant Cost ($/kW)†	Electricity Cost (mills/kWh)‡
1	Illinois No. 6	As-mined coal is fed to the gasifier in a water slurry at a concentration of 66.5 wt% dry solids.	0.47	1410	43.9
2	Lignite	Conventionally dried lignite is fed to the gasifier in a dense-phase pneumatic flow with recycle syngas carrier at a concentration of 98 wt% wet solids.	0.43	1430	33.8
3	Lignite	Conventionally dried lignite is fed to the gasifier in a dense-phase pneumatic flow with recycle CO_2 carrier at a concentration of 96 wt% wet solids.	0.42	1440	33.8
4	Lignite	Conventionally dried lignite is slurried in liquid CO_2 at a concentration of 88 wt% wet solids; slurry is heated to vaporize the CO_2 before the mixture enters the gasifier.	0.42	1500	35.4
5	Lignite	As-mined lignite is slurried in water at 50 wt% dry solids; slurry water is vaporized; about 50% of steam is removed (skimmed) in a cyclone; lignite is fed to the gasifier with steam at a concentration of 66.7 wt% dry solids.	0.42	1460	34.6
6	Lignite	Lignite (dried with hot water under pressure) is fed to the gasifier in a water slurry at a concentration of 60 wt% dry solids.	0.52	1630	38.3
7	Lignite	As-mined lignite is fed to the gasifier in a water slurry at a concentration of 50 wt% dry solids.	0.59	2305	42.0

*Oxygen (100%)/coal carbon (molar ratio).

†Total capital requirement (e.g., contingency, working capital, AFDC) in mid-1984 dollars.

‡Thirty-year levelized mid-1984 constant dollars, investor-owned utility. Illinois No. 6 and lignite coal cost $2.25 and $1.15 per million Btu, respectively.

The Texaco coal gasification process has been demonstrated at commercial scale with bituminous coals at the Cool Water IGCC facility near Barstow, California, and at Tennessee Eastman Co.'s coal-to-chemicals facility in Kingsport, Tennessee. The Texaco process uses a controllable, high-pressure water slurry transport system to feed coal to the gasifier. The process is at a disadvantage, therefore, when gasifying a lignite coal because of the lignite's high-equilibrium moisture compared with that of bituminous coal and the correspondingly high total water content of the slurry feed. The higher water content of the feed results in higher oxygen consumption, with an attendant increase in IGCC plant cost and a decrease in net power output.

EPRI funded a project with Energy Conversions Systems, Inc. (ECS), to address the problems associated with using Texas lignite in Texaco IGCC power plants (RP2221-1). The major objectives of the research were to identify and evaluate alternative methods of feeding lignite to the Texaco gasifier that would eliminate the disadvantages of carrying surplus water into the gasifier and to determine the relative cost of producing electricity in IGCC power plants that use Texas lignite and bituminous (Illinois No. 6) coal.

ECS researchers designed and developed capital and operating costs for seven Texaco IGCC power plants (Table 2). As can be seen, the base case reference plant (case 1) was fueled with Illinois No. 6 coal and used a conventional water slurry for transporting the coal to the gasifier. The remaining six plants were fueled with lignite coal and used three different systems for transporting coal to the gasifier—a pumpable water slurry, a pumpable liquid carbon dioxide (CO_2) slurry, and a dry dense-phase transport with either gaseous CO_2 or recycle syngas.

Researchers used two approaches to reduce the water content for those plants employing a lignite-water slurry feed. In one approach (case 5) they heated the slurry to vaporize the water and concentrated the coal solids in a cyclone separator before feeding to the gasifier (a skimming operation). In the second approach (case 6) they reduced the equilibrium moisture content of the lignite by drying with hot water under pressure. A plant with a conventional lignite-water slurry feed (case 7) was included to complete the study.

The slurry water requirement was completely eliminated in cases 2, 3, and 4 by using either dense-phase pneumatic transport or liquid CO_2 slurry transport for feeding the lignite fuel. Dense-phase transport by syngas carrier (case 2) requires recycling a small quantity of carrier product gas back to the gasifier with the feed coal, which results in a slight increase in gasifier oxygen consumption and gas plant mass throughput.

For dense-phase transport with gaseous CO_2 (case 3), the required CO_2 carrier gas must be recovered from the cleaned product gas in a separate acid gas removal unit (Amine Guard process). For slurry transport by liquid CO_2 (case 4), the required CO_2 carrier fluid must also be recovered from the product gas in a separate acid gas removal unit, and another separate system is required for liquefying the recovered CO_2 gas prior to slurrying with coal.

The design bases for the seven IGCC plants evaluated in this study were primarily selected to maintain continuity with previous EPRI studies. All the plant designs and costs for the seven study cases were factored from a prior Texaco IGCC plant design (EXTC–MOD2) that used an Illinois No. 6 coal feed (AP-3129). EXTC–MOD2, in turn, was based on the original design and cost estimates for IGCC plant EXTC-79 (AP-1624).

Early in the ECS study, trade-off studies showed that significant improvements could be made to Texaco IGCC plants by the judicious selection of commercially available processes for acid gas removal and tail gas treatment. Specifically, the trade-off studies indicated that Union Carbide Corp.'s H–S and Sulften processes were superior to the Selexol (acid gas removal) and Beavon-Stretford (tail-gas treatment) processes used in EXTC–MOD2.

Following the trade-off studies, the design for base case plant EXTC–MOD2 was modified to incorporate the H–S and Sulften processes. The revised plant (case 1 in this study) is considered the reference base case plant design. The designs for the six evaluated lignite IGCC plants (cases 2–7) also incorporate the H–S and Sulften processes.

The Chicago area was the site for the Illinois No. 6 coal plant design (case 1) and the Dallas area was the site for the Texas lignite plant designs (cases 2–7). The Illinois No. 6 coal was assumed to be delivered to the plant site in a washed and sized condition, and the lignite coal, in an as-mined state. On an as-received basis, the moisture content of the Illinois No. 6 coal was 12 wt%, the sulfur content was 3.8 wt%, and the higher heating value was 11,241 Btu/lb; for the lignite coal, the moisture content, sulfur content, and higher heating value were 34.9 wt%, 0.89 wt%, and 6826 Btu/lb, respectively.

The lignite in cases 2, 3, and 4 was dried from 34.9 to 12.0 wt% moisture in conventional rotary drum dryers prior to grinding and then pulverized in unheated ring roller mills. The heat required for drying was supplied by sensible heat available in the heat recovery steam generation (HRSG) stack gases.

The lignite in case 6 was dried from 34.9 to 12.0 wt% moisture at 1200 psi (8 MPa) and 626°F (330°C) with hot water obtained from the HRSG economizer. The design of the lignite drying equipment is based on results of an EPRI project with the Energy Research Center, University of North Dakota (AP-4262). Data from the research show that drying high-moisture-bearing, low-rank coals with hot water or steam under pressure can effectively reduce the equilibrium moisture content of the coal by as much as two-thirds. In addition, rheological studies indicate that slurries of water and lignite dried under pressure can attain a dry solid concentration of 60 wt% (the value used as the design basis for case 6). As-mined lignite-water slurries are limited to about 50 wt% dry coal content (the value used as the design basis for case 7).

The design of the coal-liquid CO_2 slurry equipment for case 4 was based on data from an EPRI project with Arthur D. Little, Inc. (RP2469-1). Recent data from ADL's pilot plant pipe loop viscometer indicate the maximum attainable wet solids content of coal in a pumpable CO_2 slurry to be 88 wt%.

The power block design for all seven evaluated cases is based on currently available combustion turbines having a firing temperature of 2000°F (1100°C) at the combustor exit. The steam cycle is a 1450 psig (10 MPa) system (turbine throttle) with 900°F (480°C) superheat and a single 900°F reheat. A single steam turbine generator system is employed. Efficiencies of the individual back-pressure and condensing ends of the steam turbine are the same as those used in the EXTC-79 study (AP-1624).

To facilitate the factoring of the gas turbine design from IGCC plant EXTC–MOD2 and to achieve comparable costs, the quantity of total heat content in the fuel gas to the gas turbine combustor was selected as the common denominator for all seven cases. Each design case, therefore, had a total clean fuel gas heat rate of 7380 million Btu/h (lower heating value), and the coal feed rates were selected to match that production.

In all plant designs for this study, the only net plant products are electricity and elemental sulfur. Total gaseous emissions of NO_x and sulfur compounds are designed to be within the limits set by the revised EPA standards (June 11, 1979), which apply to a new coal-fired boiler plant. On the basis of these regulations, 90% of the sulfur contained in the feed coal is recovered as elemental sulfur. Stack gas NO_x is controlled by humidifying the fuel gas to a steam concentration of 40 wt% prior to combustion in the gas turbine.

Table 1 gives selected results from the evaluation of the seven Texaco IGCC power plants. The major conclusions from the study are as follows.

- The electricity costs for lignite cases 2–6 are substantially lower than those for bituminous coal, case 1. Therefore, it may be stated that with properly designed coal feed systems, Texaco IGCC power plants using lignite have the potential to generate power at costs that are lower than those using bituminous coal.

- As can be seen from cases 2–7, the cost of electricity for a given coal is proportional to the oxygen consumption (i.e., the higher the O_2 consumption, the higher the electricity cost). Also, lignite cases 5–7 demonstrate that oxygen consumption and the cost of electricity increase with an increasing water content of the gasifier feed. Case 7, a conventional water slurry feed, is clearly not cost-competitive with any of the other lignite study cases.

- Dense-phase pneumatic feeding of lignite coal with either recycle syngas (case 2) or gaseous CO_2 (case 3) is the lowest-cost option for generating electricity. CO_2 slurry feed (case 4) is also attractive, comparing favorably within the accuracy of these cost estimates with a skimmed-water slurry feed (case 5). Although the liquid CO_2 and skimmed-water slurry feed cases have predicted costs that are slightly higher than the dense-phase transport cases, the slurry systems have an advantage in that they provide conditions that are amenable to flow control of the feed coal to the gasifier.

It should be noted that the lower cost of electricity for lignite cases 2–6, compared with that for bituminous coal (case 1), reflects the lower cost assumed for the lignite coal—$1.15 per million Btu for lignite versus $2.25 per million Btu for Illinois No. 6. In the instance where lignite costs are comparable to bituminous coal costs (e.g., where lignite mining and transportation costs are higher than those assumed in this study), the bituminous coal plant (case 1) would give the lowest cost of electricity for all the cases studied.

It should be further noted that the proposed schemes for reducing or eliminating the water content of the slurry feed for lignite cases 2–6 need further development. For example, researchers have to demonstrate that dry dense-phase feed systems (the feed systems with the lowest electricity cost) provide the flow control required for feeding coal to an entrained gasifier. RP2469-1 yielded some rheological data on low-rank coal-liquid CO_2 slurries; and limited data are available to support the water skimming concept and the hot water drying of coal at pressure (AP-4262). All these proposed schemes, however, have to be tested on a larger scale in a Texaco gasifier with lignite feed. *Project Manager: Michael Epstein*

R&D Status Report
COAL COMBUSTION SYSTEMS DIVISION

Kurt Yeager, Vice President

FOSSIL FUEL PLANT LIFE EXTENSION

Fossil fuel generating units have traditionally been built with an assumed life of 25–30 years. The expectation was that these units would be replaced with new units to meet load growth requirements and, through advances in technology, to produce power at lower cost. This expectation has not been realized because of low load growth, high interest rates, escalating construction costs, and uncertain regulation. As a result, the average age of existing generating capacity is increasing, and utilities are interested in keeping units in service for 40–60 years or longer. This report describes EPRI's current and planned research to develop generic guidelines to help utilities devise strategies for keeping units in service as long as economically practical.

As units age, critical components may degrade through such mechanisms as erosion, corrosion, creep, fatigue, and creep-fatigue interaction. The condition of these critical components and the time remaining before replacement or major repair is required are major considerations in the cost of keeping older units in service. In addition, equipment degradation in older units may lead to increased maintenance requirements in order to attain desired levels of availability and performance. Determining unit cost is further complicated if operating strategies are implemented that sacrifice unit performance to extend the life of critical components.

The objective of a life extension program is to identify and implement a strategy for keeping a generating unit in service as long as is economically practical. The development of such a strategy requires the cooperation of corporate planners, financial and system planners, and plant operations and engineering personnel. The implementation of life extension affects most aspects of subsequent plant operation through a phased program of inspections, capital expenditures, and operating and maintenance (O&M) practices.

In its effort to develop generic guidelines for fossil fuel plant life extension, EPRI has sponsored six projects to explore and document activities that are part of the life extension process.

- RP2596-2 and -3 supported the development of reference guidelines for life extension at Boston Edison Co.'s Mystic Unit 6 and Niagara Mohawk Power Corp.'s Huntley Unit 67.

- RP2596-4 and -5 supported Consumers Power Co. in developing a set of generic guidelines for analyzing plant life extension from the standpoints of corporate planning, financial planning, environmental planning, and risk analysis.

- RP2596-6 supported an engineering evaluation of the boiler and turbine at Pacific Gas and Electric Co.'s Pittsburg Unit 5.

- RP2596-1 supported the integration of the findings of these EPRI projects and other industry programs around the world into a set of generic guidelines that a utility can use to develop its own unique life extension strategy.

EPRI's generic guidelines describe the life extension process in terms of three steps—corporate planning, life extension planning, and life extension plant operation. These are not discrete, sequential steps but are related in time and by information requirements. Basically the same steps are necessary whether a utility decides on an incremental (phased) approach or a front-end refurbishment approach, which entails an initial extended outage.

To integrate the steps, the guidelines include a life extension program management system. This system, which features an integrated life extension decision (ILED) model, will support the data gathering, organization, and analysis required for a plant- or system-wide program. It facilitates the scheduling of component inspections and any necessary repairs or modifications to minimize outage and maintenance costs and maximize system and unit generation.

Corporate planning

At the corporate planning level, the life extension option must compete for funds against a variety of other alternatives—among them, demand-side planning, new generation technologies, power purchases, and new conventional central station plants. From a system planning perspective, the value of the life-extended plant to the utility system not only must exceed the costs of life extension but also must compare favorably with the other generation alternatives. The financial effects of life extension projects must meet the utility's financial goals, and provisions must be made for complying with current and expected environmental regulations.

The selection of plant life extension goals includes defining the life extension period, the required plant availability and efficiency, the power output, the energy costs, and the expected total costs of the tasks necessary to extend plant life. Historical O&M data for components from the candidate plants will be augmented with generic component data from the industry to provide a basis for initial estimates of the plants' remaining useful operating life and the projected costs of life extension.

These costs are then used in a more detailed system planning study to verify the ranking of the units in terms of their suitability for life extension. Finally, these rankings, and the associated costs and benefits of potential life extension projects, are used by corporate planners in comparisons with other major investment alternatives.

The preliminary findings of the Consumers Power study (RP2596-5) suggest that a company's historical O&M philosophies and practices will to some degree determine the approach it should follow in evaluating life extension. Initial projections also indicate that with the exception of major environmental control projects to comply with changing regulations, the incremental costs associated with extended-life operation at Consumers Power are relatively small. Because the costs are not large, the ranking of units is determined almost entirely by the benefits calculated in the system planning analysis.

Life extension planning

Once a unit has been selected for life extension, a program plan must be developed for the scope and schedule of life extension activities. The objective of the plan is to minimize the cost of the life extension effort and to maximize plant availability and efficiency for a sequence of repairs and inspections within a given cost.

The most important operating decision is to select which components in a unit are to be managed through the life extension program. Components fall into two categories on the basis of failure mechanisms and their consequences. One category consists of components critical to continued plant operation; these should be considered at this stage for all units. The other category consists of components selected in reaction to current or anticipated problems; these will be unit-specific. Components in the first (critical) category are as follows.

- Steam generator: drums (steam and lower), superheater headers, reheater headers, waterwall headers, downcomers, main steam piping, hot reheat piping, economizer inlet headers
- Turbine: rotor, shell, steam chest, casing
- Generator: rotor, stator windings, insulation, transformer
- Balance of plant: intake and discharge structures, structural steel, stack liners, station main transformers

For both component categories, critical and reactive, an initial inspection plan is developed on the basis of the failure mechanisms and the design and operating history of the components. The consequences of failure are identified and quantified in dollars. Then, after each O&M cycle, the data collected are analyzed and used to revise the plan. Information on plant condition and the need for repair or modification of the components managed through the life extension program will be provided to corporate planners for use in their annual review of resource allocation decisions.

It is important that the scope of the initial inspections for both component categories be selected so as to complement current information. An initial phased inspection plan should be developed on the basis of inspection costs and the value of the information to be obtained.

The process a utility uses to select components can itself become expensive because of the number of components involved. To facilitate this process, the generic guidelines present simple plant models to serve as a consistent evaluation mechanism for all plants.

Life extension plant operation

Once a utility has completed the planning activities and has selected the components to be evaluated, detailed scheduling is necessary so that the critical component inspections and modifications can be performed within the framework of normal utility operation and maintenance.

Methods for assessing the remaining useful life of plant components are a critical part of EPRI's effort to formulate life extension strategies for fossil fuel power plants. They are necessary for determining not only remaining life but also appropriate operation and inspection intervals. The generic guidelines delineate life assessment methods and, through the program management system (specifically the ILED model), provide a tool for controlling the scheduling and costs of residual life inspection and analysis. EPRI continues to support work to develop and improve residual life assessment techniques. The components currently being addressed are boiler pressure parts and tubing, steam pipes, and steam turbine rotors.

The research on boiler pressure parts has made significant progress in relating creep damage to the extent of creep cavitation. In combination with replication techniques, this information provides a nondestructive, quantitative life assessment tool (RP2253-1). In other efforts, currently used accelerated rupture tests for assessing remaining life have been evaluated and refined; miniature specimens have been developed that can yield the same information now provided by large specimens (RP2253-1); and a fracture-mechanics-based methodology for estimating creep crack growth has been established (RP2253-7). It is expected that the integration of all these efforts will represent a major advancement in life assessment (RP2253-10).

EPRI is also investigating acoustic emission monitoring of cracking (RP734-6), using retired headers and field testing. Preliminary results from the monitoring of a cracked header at Wisconsin Public Service's Pulliam station indicate that ligament cracking may be detectable.

In the area of boiler tubing, the measurement of steam-side oxide scale thickness to predict remaining life is being evaluated (RP2253-5); researchers are also comparing this technique with a variety of methods based on wall thickness measurements, microstructural information, and destructive tests to determine its relative merits (RP2253-10). In another project a code called PODIS (prediction of damage in service) has been developed for assessing the condition of dissimilar-metal welds on the basis of nondestructive analysis (EPRI CS-4252).

Much other work is being sponsored to improve the nondestructive evaluation of boiler tubing. Ultrasonic testing (UT) guidelines for assessing boiler tube damage have been developed under RP1865-5. Techniques for assessing wall thickness, cracking, pitting, and hydrogen damage are covered, as well as surface preparation, personnel qualifications, available equipment, and costs. A computer code for analyzing UT data and determining optimal inspection intervals has also been developed. An alternative to UT boiler tube thickness measurement—the electromagnetic acoustic transducer—is being investigated in RP1865-3. This technique is generally limited to wall thicknesses greater than 0.1 in (2.54 mm). EPRI is also evaluating the use of acoustic leak detectors for monitoring boiler and feedwater heater tube damage; data from the first U.S. utility installations are being collected and the benefits assessed (RP1863-2).

With respect to steam pipes, preliminary guidelines for currently available inspection and life assessment technology have been prepared (RP2596-7). The capabilities and limitations of ultrasonic and radiographic techniques for detecting cracks in steam pipes are being investigated by using pipe samples with a variety of known embedded flaws. Also, a computer code that will predict remaining life under creep crack growth conditions has been developed for longitudinally welded pipes (RP2596-7).

In addition, new inspection and monitoring techniques that can potentially reduce inspection costs and improve coverage are being pursued (RP1893-4), including such automated inspection systems as internal pipe crawling devices, UT flaw-sizing techniques, radiography, and acoustic emissions for monitoring crack growth and leak formation. These advanced techniques will be incorporated into the guidelines for the inspection, monitoring, and evaluation of the entire steam line system.

In research on steam turbine rotors, several nondestructive techniques for assessing the toughness degradation of in-service rotors, such as Auger analysis, chemical etching, and the use of single Charpy specimens, have been developed (RP559, RP2257-1). Methods for estimating toughness on the basis of chemical composition are being investigated in

RP2481-2. A previously developed computer code caller SAFER (stress and fracture evaluation of rotors) is being updated in RP2481-3; the improved version will be available in the next 18 months. A materials data handbook on rotors is also in preparation (RP2481-4).

The early detection of problems can often minimize or eliminate forced outages and can facilitate the scheduling of spare parts and manpower for planned outages. Diagnostic monitoring offers the ability to predict and detect equipment failures in their incipient stages and thereby to avoid costly damage or even catastrophic failure. EPRI is sponsoring the development and demonstration of several diagnostic monitoring systems. Of particular interest are the current demonstrations of a boiler stress analyzer at Consolidated Edison Co. of New York (RP1893-1) and continuous vibration signature analysis systems at Philadelphia Electric Co. and United Illuminating Co. (RP1864-1, -2). A boiler stress analyzer tracks the long-term creep-fatigue damage in headers, drums, and steam lines. Both turbine and boiler stress analyzers can extend the life of heavy-walled components by helping operators minimize thermal stresses during frequent startups and load swings. A computer-based continuous vibration monitoring system can curtail major failures in the turbine generator, feedwater pumps, and fans by detecting such damaging conditions as steam whirl, oil whip, shaft cracking, misalignments, blade rubbing, and bearing deterioration.

Program management system

The objective of all the plant evaluations is to collect data to support decision making on life extension alternatives. In order for the data to be useful, they must be analyzed to determine how the condition of the equipment affects plant performance and the equipment's remaining useful life. This analysis must provide estimates of life and cycle life expended and of remaining useful life; indicate the operating parameters that can be controlled or limited to extend remaining useful life; make recommendations regarding replacement under current, projected, and/or modified O&M practices; and indicate the degree of uncertainty inherent in the analysis results.

Data from the O&M and inspection cycles and from accelerated testing will be analyzed by using the program management system's ILED model to determine the minimum-cost approach. The life extension plan and the maintenance plan will then be revised to effect the minimum-cost life extension program to meet the goals set for the specific plant. The ILED data on the costs and performance of the life extension program can be fed back to corporate planners to be used in evaluating continued funding of the program.

When an analysis of the results of various inspections indicates that major expenditures are required, the life extension program management system helps utility planners identify and analyze their potential options. The ILED model includes five submodels whose outputs are the decision measures used by management in allocating resources to any life extension program: power (kW); availability (h/yr); energy costs (mills/kWh); total costs ($/yr); and schedules (h/yr). This much-needed life extension tool enables a utility to evaluate any number of units in its system over a period of time.

In summary, the EPRI generic life extension guidelines developed under RP2596 provide the basis on which a utility can develop its own life extension strategy. Plant life extension starts with the current state of the plant as determined from plant design and O&M data and from generic industry information. These data are used in corporate planning as the initial data set from which to estimate the plant's expected remaining useful operating life. If, after evaluating future energy-producing options, corporate planners select the life extension option, they prepare a plan that will meet the goals set. The operations group then develops the initial life extension plan, defining the necessary tasks. The life extension management system, featuring the ILED model, supports the implementation of the plan. Each subsequent plant O&M cycle produces new data, which are analyzed with the model, and the plan is revised in terms of cost and schedule for work required to keep the plant at the desired performance levels.

Although the life extension tools have been developed for aging fossil fuel plants, utilities can and should use them on newer units. Likewise, the residual life assessment techniques developed under RP2253 and RP2481 should be used on equipment as early in its operating life as possible.

EPRI plans to work closely in the future with a number of utilities to demonstrate these methods and operating philosophies—especially the program management system. *Project Manager: R. B. Dooley*

ESP INTERMITTENT ENERGIZATION

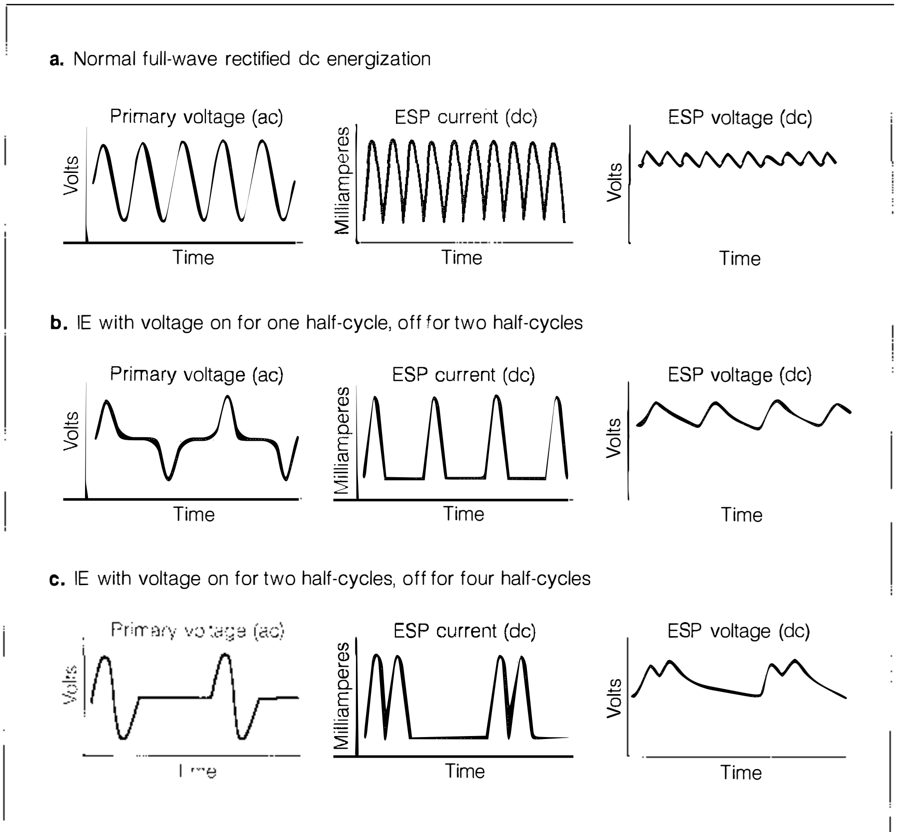
There are over 1000 electrostatic precipitators (ESPs) in service at utility plants for fly ash emission control. The power consumption of the transformer-rectifier (TR) sets of these precipitators is affected by both ESP size and application. For high-efficiency precipitators, EPRI data indicate that average ESP power consumption costs 0.238 mill/kWh. For a 500-MW unit, the power consumed by the ESP's TR sets is equivalent to about $675,000 a year on the basis of a 65% capacity factor. A recently developed method for controlling ESP power supplies—intermittent energization (IE)—has the potential to reduce the power consumption of most precipitators and, under some circumstances, to improve performance as well. Many currently installed ESP controllers can be reset for IE at no cost and with no disruption of service. For controllers not now designed for IE, new solid-state circuits are available that can enable reliable, inexpensive controls to be built in for as little as $2000–$5000 per TR set.

Conventional ESP controls normally operate by applying unfiltered full-wave or half-wave rectified dc voltage to the discharge electrodes in the precipitator. When IE controls are used, the voltage to the precipitator is turned off during preselected half-cycles or whole cycles of operation. All voltage-current control occurs on the primary side of the TR.

Figure 1a shows, in simplified form, the ac voltage applied to the primary side of the TR, the dc voltage applied to the discharge electrodes, and the current flow with normal dc energization. Figures 1b and 1c show voltage and current for two common IE schemes. In Figure 1b the primary voltage is turned on for one half-cycle and off for two half-cycles; in Figure 1c it is turned on for two half-cycles and off for four. The dc voltage on the discharge electrodes does not decay to zero in either IE scheme, even when the primary voltage is turned completely off, because the precipitator acts as a capacitor during the very short off-cycle time periods. Such IE schemes result in the consumption of much less current and therefore less power. The pattern in Figure 1b is said to have an IE ratio of 1:3; that in Figure 1c, 2:6. These are the most commonly used IE ratios. Other ratios can also be used effectively under certain site-specific conditions.

To determine the effects of IE control on both ESP power consumption and performance for a wide range of operating conditions, a comprehensive pilot-scale test program was initiated under RP1835. The work was conducted by Southern Research Institute at the Arapahoe Test Facility in Denver, Colorado, using a pilot ESP that can treat flue gas at flow rates of 3500–5000 actual ft^3/min (1.65–2.36 m^3/s). Controls capable of IE operation were installed on this ESP, and tests were conducted from July through December 1985. The pilot ESP was equipped with an SO_3 conditioning system so that the resistivity of the fly ash, which is normally high, could be varied from 10^{12} Ω-cm to approximately 2×10^{10} Ω-cm, the optimal

Figure 1 The use of IE controls can reduce ESP power consumption, as illustrated by voltage and current waveforms for conventional full-wave rectified dc energization (**a**) and two IE schemes (**b, c**).



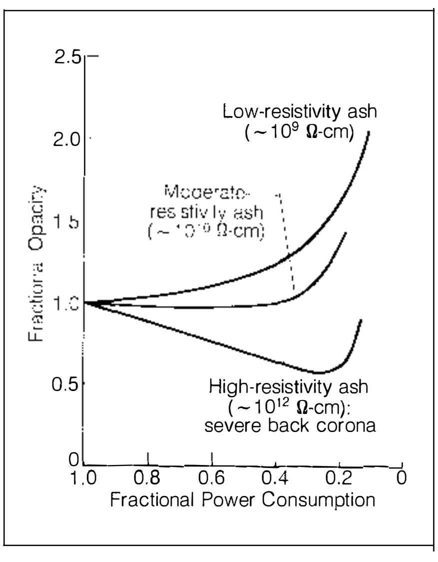


Figure 2 Pilot-scale tests were conducted to determine the effect of IE on ESP outlet gas opacity and power consumption for fly ashes of different resistivities. Fractional opacity is the ratio of IE opacity to opacity with conventional energization; fractional power consumption, the ratio of IE power consumption to conventional power consumption.

value for ESP operation.

In a series of parametric tests, the opacity of the outlet flue gas was measured to determine ESP performance trends over a wide range of conditions. In a smaller number of comprehensive tests, total mass and particle-size-dependent collection efficiencies were determined to thoroughly characterize performance under selected conditions. Figure 2 shows typical results from testing IE patterns of the types illustrated in Figure 1.

The tests demonstrated that the effect of IE depends on the resistivity of the ash being collected in the precipitator. When fly ash resistivity was low, the outlet gas opacity increased slightly with any decrease in power consumption. For moderate-resistivity ash, however, power consumption could be reduced significantly with no increase in opacity. The data obtained when the precipitator was operating in severe back corona, a result of the collection of high-resistivity fly ash, are more impressive. Under these conditions, opacity decreased and collection efficiency increased at the same time that power consumption was reduced.

It should be noted that IE effectiveness is more easily quantified if the ability of IE to reduce ESP power consumption and improve performance is related to electrical conditions in the precipitator rather than to the ash resistivity that influences these conditions. Electrical conditions—defined by the voltage-current relationship in an ESP—can be measured more precisely than ash resistivity. Measuring the voltage-current relationship can help determine where in the range between spark limit (optimal, nondegraded conditions) and back corona (degraded conditions, as indicated by a voltage-current plot with a negative slope) the ESP is operating.

The IE tests are the first ESP tests conducted at the Arapahoe Test Facility in which a decrease in power consumption was accompanied by an improvement in performance. Flue gas conditioning and pulse energization have been used to improve precipitator performance, but each process has usually resulted in increased power consumption.

The trends in opacity were confirmed by measurements of collection efficiency. These data show that when the precipitator was collecting fly ash with either low or moderate resistivity and was operating at spark limit (i.e., with little or no back corona), power consumption could be reduced by almost 50% with little or no loss in performance. During the tests when the ESP was operating in back corona (i.e., under degraded conditions) because of high-resistivity ash, emissions were reduced by approximately 40% at the same time that power consumption was reduced by 50%.

Two factors appear to play an important role in explaining why IE can reduce ESP power consumption without significantly increasing emissions. First, only a relatively small fraction of the current in a precipitator actually charges the fly ash particles. Thus, it is at least theoretically possible to reduce the current without significantly reducing the charge on the fly ash particles. Second, the average voltage (and the current in the electric field) in a precipitator does not decrease dramatically when selected pulses to the primary side of the TR set are blocked. This is explained by the fact that the precipitator acts as a capacitor during the off cycles.

Future IE investigations will include full-scale tests to verify the results obtained at Arapahoe and to develop full-scale application and operating guidelines. Also, IE technology may be combined with other ESP technologies that are being investigated by EPRI—for example, wide plate spacing and flue gas conditioning. *Project Managers: Walter Piulle and L. F. Rettenmaier*

R&D Status Report
ELECTRICAL SYSTEMS DIVISION

John J. Dougherty, Vice President

TRANSMISSION SUBSTATIONS

HVDC modulation control

The unique ability to control the flow of power in HVDC systems has been exploited since the earliest days of HVDC, particularly for improving the dynamic performance of ac systems. The reactive power consumption of the dc converters, however, especially those with weak ac systems, has limited the controlling actions of HVDC systems. The advent of a modern control design technique in tandem with the high-speed computation capabilities of microprocessors has significantly increased the performance capabilities of HVDC modulation systems.

The objective of this project is to increase dynamic performance of ac/dc systems by modulating the HVDC system's active and reactive power flows (RP1426-4). This permits higher ac line loadings for a given reliability index. Previous projects resulted in a central modulation controller, which modulates dc power and voltage in response to rectifier bus frequency to increase the steady-state stability of the ac system. This controller was implemented in contemporary digital hardware (Intel 8086 base), and its performance was demonstrated on a General Electric Co. simulator. However, the central controller requires the communication of the dc voltage modulation signal from the rectifier to the inverter terminal and thereby may affect the reliability of the modulation system. The current project has effectively eliminated the communication requirement by developing a decentralized control system (Figure 1). Also, the small-signal modulation system was extended to include large-signal modulation to improve the transient stability of generators near the converter terminals.

The control techniques of the previous projects were developed and demonstrated on small-scale synthetic ac systems with realistic performance limitations. Future effort is planned to demonstrate the control techniques on an actual large-scale power system (Mid-Continent Area Power Pool). The current project was extended to demonstrate the feasibility of deriving a modulation controller design model from a large-scale stability studies data base. Test results of this model will be verified by comparison with field measurements. EPRI then plans to design, build, and field-test a commercial-grade digital modulation control system for the Square Butte dc system. *Project Manager: Selwyn Wright*

Pyrolysis and combustion of PCBs

PCB involvement in utility fires has become a prime consideration in seeking to reduce potential public liability. This project was initiated in response to the twin problems of contaminated mineral oil and high-level (up to 5%) contamination of retrofill fluids during part of the retrofill period.

New York State Health Dept. is examining pyrolysis and combustion products of PCBs at 100% concentration and as 5000, 500, and 50 ppm contaminants in mineral oil, silicone, and tetrachloroethylene (RP2028-4). We speak of pyrolysis here as partial oxidation at elevated temperature in an oxygen-deficient atmosphere. Combustion is defined as partial or complete oxidation in the presence of a flame with adequate oxygen supply. Tetrachloroethylene, although it is normally considered a replacement fluid, may (under some circumstances) be found in certain retrofill processes.

Results to date for pyrolysis and combustion of Aroclor 1254 in all three test fluids show roughly linear conversion yields of PCBs to polychlorinated dibenzofurans (PCDFs) as the PCB concentration in the feed mixture is decreased. Maximum yields occur around 550°C in all cases. Below this temperature, conversion to PCDF is slow, while at higher temperatures, PCDF is destroyed faster than it forms.

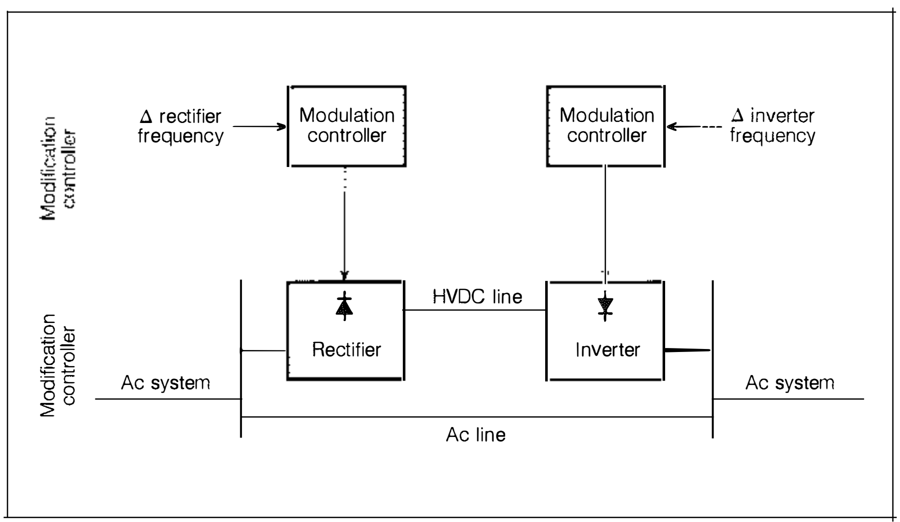


Figure 1 A decentralized control system for modulating the power and voltage of HVDC line terminals eliminates the need for a communication link between the inverter and rectifier of an HVDC line connecting two ac systems. This improves the overall reliability of the interconnection, while taking advantage of the increased performance capabilities of modern modulation systems (high-speed computation permits rapid response to power swings).

Work on an in vitro bioassay to integrate the PCDF-like physiologic activity of all the partial oxidation products formed has run into some difficulty because of interference with the test by the bulk dielectric fluids present. Steps are being taken to mitigate this problem.

The results of our laboratory trials are found to be significantly different from those of other workers in the field. This fact brings with it a word of caution in applying any of these results to real-world PCB fires (except for use as a guiding principle) because each real fire, under completely random conditions, is different from all others. Even within a given fire, there will be an infinite range of competing reactions. It can be assumed that only a small portion of the combustion process has optimal conditions and that the combustion process varies with time, leading to the partial destruction of the various combustion by-products. Thus, all the research being done must be considered as setting a boundary or worst-case condition that gives a general direction to the investigation of the real world.

Another contamination material to be examined in this project will be trichlorobenzene/tetrachlorobenzene, sometimes used as a diluent for PCB. The pyrolysis and combustion products of pentachlorophenol, used in large quantities as a wood preservative, will also be examined. *Project Manager: Gilbert Addis*

UNDERGROUND TRANSMISSION

Computerized data base on dielectric materials

As described in the October 1984 issue of the *Journal*, the intent of this project (RP7897-5) is to provide a central source of reliable data on the technical, commercial, and environmental properties of all dielectric materials. The reason for establishing such a data base is that the yearly worldwide addition of some 3000 pertinent documents to the existing body of over 60,000 documents does not permit an individual involved in research, development, and manufacture of dielectrics and electrical equipment to adequately stay abreast of new developments. The data base covers several hundred properties and information items in the following categories.

- Physical properties
- Electrical properties and phenomena
- Thermal properties and phenomena
- Chemical properties and phenomena
- Optical and thermoradiative properties
- Mechanical properties
- Flammability properties and information
- Health hazards
- Processability
- Availability and cost
- Usefulness and applications
- Material characteristics
- Parameters and other information

One particular strength of this data base is that in addition to containing the raw numerical data as published, it includes an analysis of the data; as raw data may vary in quality, reliable preferred values are also available.

At the user's option, access to the data base will range from written or telephoned requests to direct and interactive access from the user's computer terminal by telephone lines. Users will be able to extract data in whatever format they desire, tabular or graphic, and in whatever units they prefer. Further, the system will support on-line statistical analysis and mathematical manipulation of the data.

The data base will be exceedingly simple to use. No knowledge of computer operations is required of the user in the interactive mode because the user is guided by a simple menu system.

The initial phase of this project was the development of a pilot data base limited to dielectric fluids as a proof of concept. This phase has been successfully completed, and the data base on dielectric fluids is now up to date. Analysis and synthesis of these data have commenced. Currently in progress is the loading of data on gases and selected solids. Commercial operation of the data base is expected to commence early in 1987.

This work is being carried out by the CINDAS group (Center for Information and Numerical Data Analysis and Synthesis) at Purdue University under the direction of C. Y. Ho. *Project Manager: Felipe G. Garcia*

DISTRIBUTION

Distribution communication, automation, and load control

In the September 1982 issue of the *EPRI Journal* we described a unique pilot AM broadcast two-way communication concept that was demonstrated in Los Angeles, California (RP1535-1). The success achieved in this southern California pilot encouraged the EPRI staff and the Distribution Advisory Task Force to proceed with a 1000-point (500 points outbound, 500 points return) large-scale test (RP1535-3). Philadelphia Electric Co. (Peco) was selected as the host utility because of its proximity to the heavily populated area around New York City and the inherent high volume of radio transmission activity. To use an old cliche, "if it works here, it should work anywhere."

The unique communication concept employed involves synchronizing a network of remote receivers to the highly reliable and accurate radio carrier frequency of an existing AM broadcast (in this case station WCAU). In some applications, the return link transmitters are involved as well. The forward (outbound) link digital signals are superimposed on the broadcast signal in a noninterfering manner and are communicated at 16 bits per second to the remotely located transmitters/receivers (transceivers). Because high-power AM station ranges exceed 100 mi (161 km), one broadcast station can cover a large portion of most utility service areas. The return link consists of a VHF transmitter module (of the remote transceiver) at each customer location that is synchronized with a central radio receiver. A central receiver can usually receive the VHF signals from transceivers within a 15–20-mi (24–32-km) radius. The receiver can provide several narrow-band subchannels, which, in turn, improve the signal-to-noise ratio and channel utilization of the return link by a large factor. Thus data can be returned at a rate exceeding 1000 bits per second.

Since 1982 the contractor, McGraw-Edison Co., has been occupied with the design, test, modification, manufacture, and shipment of the system hardware. Concurrently, system algorithms have been developed and computer software has been coded into operating computer programs. The system computer, a VAX 11-730, is operational, and the installed transceivers and central receivers are being exercised by the system computer to generate performance data.

Peco tests each transceiver as it is received and before it is installed in the field. One hundred and fifty transceivers will be installed at customer meters and another 350 in distribution substations. The transceivers are dispersed over a large area of the Peco system. Four central receivers are needed to effectively and reliably handle the VHF return-link-transmitted data from the appropriate transceivers. The four central receivers are installed and operating. Transceiver installation started in mid November and should be completed in January of 1986. Ten distribution automation control units have been added to the project. These DACUs will demonstrate the capability of the system to acquire analog systems data (such as current, voltage, status) convert them to digital data, and then transmit the data to the central computer.

The system test will continue through June 1986. The data will then be analyzed and system performance evaluated. This EPRI-sponsored test and demonstration of the concept at Peco should confirm the ability of this technology to make more-efficient use of the frequency spectrum available for transmission of data. The possibility of using this technology to transmit data from low-cost, return-link transmitters used in distribution automation or load management functions should also be revealed. *Project Manager: William Shula*

A 38-kV-class current-limiting protector

A current-limiting protector (CLP) provides high continuous current-carrying capability under normal operating conditions, given ultrahigh-speed current limitation under fault conditions. The time required for a CLP to limit the fault current after sensing it is about 400 μs. The current is then reduced to zero within the first quarter cycle for a symmetrical fault and within the first half cycle for an asymmetrical fault. Figure 2 shows the current wave allowed by a CLP for a 40-kA fault current, compared with that allowed during a normal three-cycle breaker operation.

Completed research established the principle of operation and resulted in the successful field trials of a 15-kV-class device for use on distribution systems (RP1142). The results of this work are reported in two EPRI final reports (EL-1250, December 1979 and EL-2724, November 1982). This research resulted in the test installation of numerous three-phase CLP systems at voltages ranging from 4.16 to 23 kV, which included 8 utility applications and 12 industrial plant applications to date.

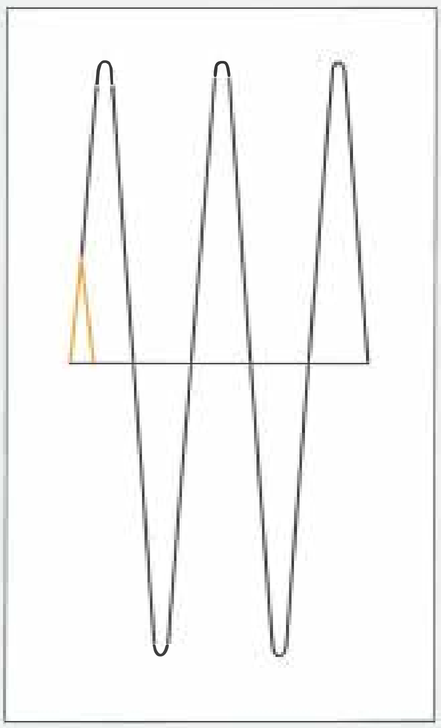


Figure 2 Short-circuit current of 57 kA peak through a three-cycle current breaker (black) and a similar fault current reduced by a current-limiting protector (color) to 21 kA. The CLP also reduces the fault energy let through from 80 to 1.9 MJ.

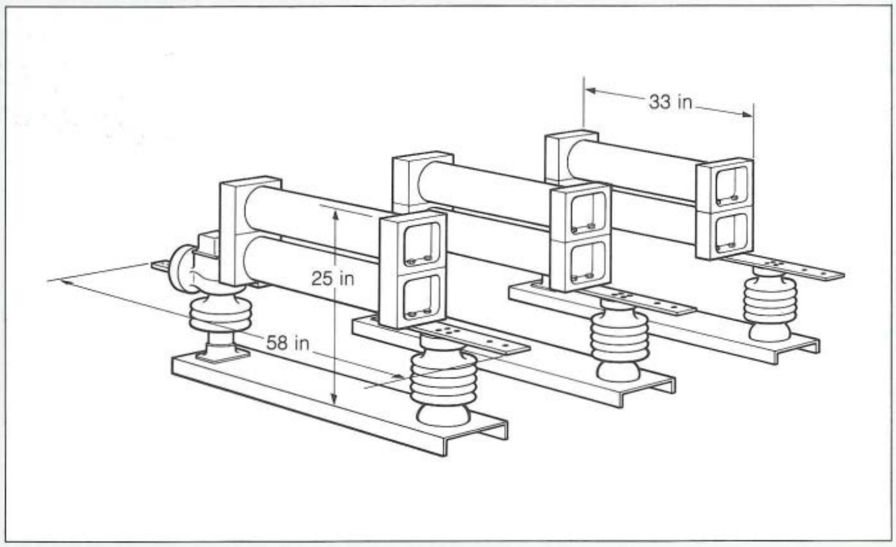


Figure 3 The 38-kV, 1200-A three-phase CLP that will be tested on a utility distribution system to confirm its reliability under actual service conditions.

Following the development of the 15-kV CLP, research continued to extend the rating of the device to 38 kV. This work is cosponsored by the Empire State Electric Energy Research Corp. and conducted by Phoenix Electric Corp. The present development project (RP1142-3) has established the following target ratings.

- Rated voltage: 38 kV (rms recovery voltage across a single device)
- Rated continuous current: up to 1.2 kA rms
- Prospective fault current: up to 40 kA rms symmetrical
- Fault-sensing level: 3–15 kA instantaneous
- Environment: indoor/outdoor

The triggering device used to date operates the CLP when fault current exceeds the set instantaneous current triggering level (3–15 kA). Under development in the current phase is a fault-sensing system that distinguishes between symmetrical and asymmetrical currents and predicts the ultimate rms symmetrical value that the fault current would have if it were not limited by the CLP. This sensing capability will allow the CLP control logic to prevent CLP operation if the predicted fault current level is within the ratings of series-connected circuit breakers or reclosers, which will operate instead of the CLP.

In December 1985 the 38-kV-class design successfully passed both preprototype and prototype high-power short-circuit current testing. Preparations for final design performance tests are now under way. Figure 3 is a perspective drawing of the final design.

On completion of the development program, extensive field test and demonstration will be conducted on a 34-kV distribution system at a large northeastern utility. This demonstration will include staged fault testing and long-term operational testing to confirm the reliability of the CLP system under actual field conditions.

CLP application satisfies several significant needs and provides the following benefits.

- Ultrahigh-speed bus sectionalizing in distribution substations
- Transformer protection to limit fault currents that can damage internal windings
- A cost-effective solution for distribution systems where short-circuit currents exceed the interrupting ratings of protective equipment
- Significant reduction in operating costs through the elimination of losses of current-limiting reactors that are paralleled with the CLP
- A replacement for fuses susceptible to fatigue or incorrect operation caused by repeated overcurrents close to their protective level

Project Manager: Joseph Porter

OVERHEAD TRANSMISSION

Reliability-based design of transmission line structures

A practical nondestructive evaluation (NDE) procedure has been developed that provides an accurate prediction of the statistical strength distribution of a group of wood poles in a transmission line (RP1352-2). This NDE method is valuable in supporting the development of reliability-based design procedures; however, this first-generation NDE method cannot predict individual pole strength.

Early project results indicated that a pole's visual appearance and even the age of the wood are not necessarily strength indicators, but that advanced sonic NDE techniques could be a very reliable means of predicting the strength of individual wood poles (Figure 4).

The goal of RP1352-4 is to develop a second-generation NDE method into a reliable and practical tool to determine the strength of individual new and in-service wood poles. The principal ongoing efforts for this project are (1) development of advanced NDE techniques to determine strength and stiffness characteristics of individual wood poles, and (2) testing of wood poles removed from in-service lines to assess the rate of strength deterioration and long-term performance and to obtain calibration data required by advanced NDE methods.

A second-generation NDE method under development is based on the sonic waveform spectral analysis method. This method involves assessment of the sonic wave characteristics as the wave travels through the wood pole. This far more powerful NDE method has the potential to accurately grade new wood poles according to their strengths and to assess in situ, in-service pole strengths. On the basis of evaluations to date, the second-generation NDE method can predict the strength of an individual pole with far greater accuracy than is currently possible with visual inspection and decay detection methods. For both new and in-service poles, the typical deviation for the relationship between measured pole strength and predicted pole strength by NDE measurements is 600 psi (4 MPa).

If a utility is to use the second-generation NDE method to determine the strength of individual in-service poles, the NDE method must be calibrated for the specific geographic area and for pole species by a limited number of full-scale destructive pole tests (Figure 5).

The need for additional in-service wood pole data for the second-generation NDE method and the need of utilities for in-service data on wood pole strength and rate-of-degradation assessments can both be satisfied with a combined test effort that provides all the data needed by both parties at a cost saving to each. Ongoing EPRI testing with Engineering Data Management, Inc. (EDM), and utilities, which collects this information on in-service poles from various geographic regions of the United States, has been under way since early 1985 and will continue until mid 1986.

Through EDM, utilities can arrange for in-service poles to be tested to destruction to provide the needed data. This effort can be an integral part of a wood pole management program. As part of the basic pole test program, additional measurements and NDE parameters are recorded for evaluation as part of the development of the second-generation NDE method. The total cost of testing to the utility is $250 per pole, plus the cost of shipping the poles to Fort Collins, Colorado. Utility funding covers the direct cost of testing the wood pole to failure and reduction of data. EPRI's funding of approximately $450 per pole and the additional support by EDM covers indirect test costs, acquisition of additional NDE data, and further development of the sonic waveform NDE method.

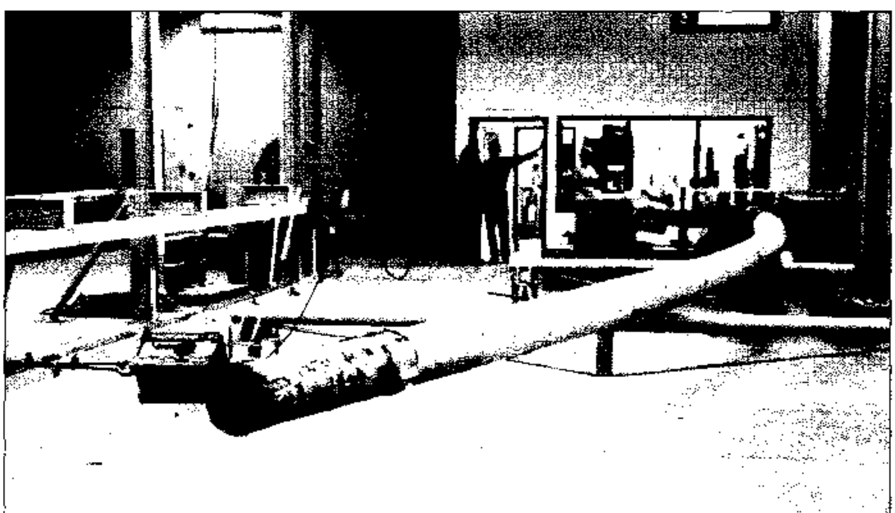


Figure 4 Full-scale testing of a new wood pole determines its mechanical properties.

Figure 5 The data necessary for determining in-service pole strength is recorded by a second-generation NDE method.

More than 150 in-service poles were tested as part of this program in 1985. Approximately 300 additional poles are promised by utilities throughout the United States for 1986. In addition, several utilities have already begun extensive field programs that use the second-generation NDE method to determine the individual strength of in-service wood poles. Their participation in the in-service wood pole test program provided the necessary calibration data for the NDE method.

The practical application of this breakthrough in technology is now available for field use by interested utilities. Existing laboratory NDE equipment and off-line evaluation of the NDE data are being used to provide individual wood pole strength values.

EPRI expects to have sufficient new and in-service wood pole correlation data available so that development of commercial second-generation NDE hardware—a soundwave analyzing black box—can begin in 1986. This hardware will provide instantaneous, direct readout of individual pole strength and eliminate the need for the present off-line data reduction to determine pole strength. *Project Manager: Paul Lyons*

R&D Status Report
ENERGY ANALYSIS AND ENVIRONMENT DIVISION

René Malès, Vice President

ADVANCED PLANNING RESEARCH

The external business environment of utilities has become less predictable and more competitive. Further, traditional capacity options are not necessarily as desirable or as feasible as in the past, and utilities are broadening their strategies to include options with which they have less experience. In light of these changes, the tasks of decision making, policy formulation, and strategic planning have become less routine and more complex for utilities. New analytic tools and quantitative information are desirable to support these tasks. By helping define the implications of decisions, they can serve to confirm intuition or else change the "mental map" of the decision maker. The communication of useful information to support decisions helps bridge the gap between the decision maker and the analyst. The advanced planning research summarized in this report, one focus of the strategic planning subprogram of EPRI's Energy Resources Program, is aimed at bridging this gap.

Utility modelers and analysts have expressed disappointment at the apparent lack of impact that good, carefully written analysis has on major decisions. Surprisingly, the same disappointment has been voiced by top utility officials. This phenomenon has also been noted in many other industries and policy-making processes. In the professional literature, it is often referred to as a crisis in management science or operations research.

Apparently, a good quantitative analysis of a problem as perceived by the analyst is not enough; factors perceived as important by the client (the decision maker) must also be addressed, and the results must be communicated—a two-way process not completely under the analyst's control. To be effective, then, the analyst not only must conduct relevant analysis, developing new quantitative tools as necessary, but also must devote a large amount of time to communication.

The strategic planning subprogram develops tools and information to support strategic problem solving in utilities: it analyzes the effect of nontraditional technology options, develops new tools for risk analysis, and identifies and studies risk management strategies. The usefulness of the resulting research products depends on how well they fit with utility planning and decision processes and on how well the information they produce is communicated—that is, on their ability to bridge the gap between the analyst and the decision maker. Thus the subprogram's research on advanced planning methods is an important component of the effort to support utility strategic problem solving. Described below are several projects that seek to develop quantitative and nonquantitative approaches to the problem of bridging the gap. This research, motivated by a utility-articulated need, will also provide insights to EPRI to help it place its research products into practical use.

Utility Modeling Forum

Under RP1303 the Utility Modeling Forum (UMF) has applied existing utility computer models to a range of current issues with the objectives of stimulating the transfer of modeling capability across the industry, promoting effective interaction between model developers and users, and identifying research needs. In the course of this work, the notion continually surfaced that how models are integrated into utility decision and planning processes is as important as the technical characteristics of the models themselves.

In a 1981 UMF report comparing utility corporate models (EPRI EA-2065), the way process issues affect the usefulness of models was evaluated by examining the planning approach of the user organization, model credibility, model design and development, and model applications. In particular, the UMF working group noted the importance of assumptions testing, communication skills, and broader direct user involvement with models.

The UMF catalyzed the development of many of the research projects discussed below, and its key findings have been confirmed time and again by in-depth analyses of the role of models in the decision-making process.

Planning methods used outside the utility industry

The objectives of this research are to identify planning methods in other industries that have possible value for the utility industry, to apply such methods to specific utility issues, and to develop a rigorous understanding of the information required to support complex, important utility decisions (RP1634). To date, a catalog of planning tools (EA-3793) and two reports on utility case study applications involving marketing planning (EA-3736 and EA-3794) have been published.

By 1984 utility analysts and managers had given EPRI much evidence suggesting that quantitative studies typically had little effect on decision making. To see if the analysts' assessment was shared by the users of the analyses, nine utility chief executives were surveyed as part of RP1634. The survey results (which were reported in Energy Analysis and Environment Division technical newsletters in February and June 1985) confirmed the analysts' observations. In general, the executives stressed that most important decisions were driven by qualitative factors and that judgment and intuition, rather than technical analyses, played the dominant role in the decision process. They were unanimous in suggesting that analysts needed to improve their communication skills.

It is clear from the survey results that if executive decision processes are to be supported, the nature of these processes must be understood. The early work in RP1634 helped define the current research activities, which include the development of a descriptive model of major decision-making processes in utilities and the preparation of a concept paper supporting the need for a new decision-making paradigm in the utility industry. In another important effort, researchers are defining a new category of techniques to support ill-structured, unique decisions—para-analytic (or nonquantitative) techniques. These will augment quantitative tools for problem solving and planning but will focus more on improving the decision process in terms of group decision making, innovativeness, and communications. These techniques will be tested this summer for a number of representative and diverse utility problems. A guidebook on their use is also being developed.

This research area continues to offer complex challenges, but it has the potential in the long run to create a new type of professional discipline for supporting decisions, one that combines an understanding of technical analysis with an understanding of the processes involved in quality decision making. EPRI is receptive to any additional participation in this project by its utility members.

Simplified models for planning support

The original focus of this effort was to develop a comprehensive approach for integrating fuel and investment decisions in utilities (RP2372). Four major challenges to integrated planning and decision making were identified: uncertainty from many sources, functional integration across many different departments, multiple criteria for choosing a course of action, and the dynamic of the decision environment. The project team concluded that current planning tools were, by and large, inadequate for effectively meeting all these challenges. It cited the obstacles to communicating complex information within organizations as an especially big problem.

Several ways to surmount the above difficulties were recommended, including the use of simplified but representative models of the decision problem called response models. There are two kinds of response model. One is a unique model created by an analyst or an executive to describe the decision system. The other is derived by using various kinds of regression equations to mimic the relationship of inputs and outputs of a large, complex model. Designed for particular issues, response models are accurate for the intended purpose but may not have many other uses. The objective of the current research is to develop a guidebook that describes the development and application of response models for problem solving and planning and that provides examples of their use in real utility situations.

The project's first report (EA-4166) presents a general discussion of integrated fuel and investment planning. Significantly, the project team concluded that the ultimate challenge is to successfully apply existing analytic tools to decision making within current organizational structures. A discussion of planning concerns cited by individual utility planners is included in the report.

Planning for nontraditional options

As part of a project on demand-side management (DSM) funded by the Demand and Conservation Program (formerly in the Energy Analysis and Environment Division and now in the Energy Management and Utilization Division), the strategic planning subprogram managed a study of the way DSM program objectives are developed in a utility organization and the role that analysis and quantitative techniques play in setting those objectives (RP2548).

The study's final report (EA-4220) emphasizes the importance of organizational issues in the initial planning of DSM programs. Many of the utility personnel interviewed cited cultural, institutional, and process problems, rather than analytic problems, as the primary barriers to implementing DSM programs. As the report notes, "Many of the issues faced by demand-side planners are soft and subjective and do not lend themselves to traditional utility analytical planning techniques." The report also includes a case study of the DSM objective-setting process at Carolina Power & Light Co.

Extending power plant life appears to be another attractive nontraditional option for utilities in the present business environment, and a study similar to the DSM study is under way for plant life extension programs (RP2074). The project team will document how utilities currently link corporate objectives and life extension strategies and will develop options for improving this process. About 10 utilities are participating in the study. Interviews being conducted with their personnel focus on four areas: the business environment, application of quantitative tools, organizational structure, and process issues. A final report is expected this summer.

Other advanced planning methods

Utilities have used scenario analysis for some time to assess the effects of alternative futures on the outcomes of current decisions. The most obvious example is the high-medium-low set of load forecasts typically produced by many utilities. However, there has been little systematic scenario planning focused on the testing of assumptions and the selection of a population of scenarios that explore, in a self-consistent way, the potential unfolding of events.

An early effort to compare scenario analysis with probabilistic approaches was conducted by the UMF. A scoping study is now under way to explore how the practice and methods of scenario planning might be applied to utility planning (RP2379-12). The study's tasks include a literature review, a workshop to bring senior utility planners and experts from other industries into a creative discussion about scenario-planning applications, and a report based on the workshop findings.

Another advanced analytic approach under study is the multiple perspectives approach. Its developer, Harold Linstone, recognized that many important real-world business and policy decisions deal with situations that are ill structured and systems that are sociotechnical. The purpose of the multiple perspectives approach is to bridge the gap between analysis and the real world of ill-structured systems. Three types of perspectives, all dealing with the "how" of seeing a problem rather than the "what," are used: technical/analytic, organizational/societal, and personal/individual. Each perspective gives important insights not obtainable with the others.

The motivation for the multiple perspectives approach is similar to EPRI's motivation in developing a research area on advanced decision-making, policy-making, and planning approaches, and a small scoping study on the potential application of multiple perspectives in the utility industry has been sponsored (RP2379-13). The study's final report (available early this summer) will describe the multiple perspectives concept, present a number of applications in typical utility decision-making situations, and suggest how the concept can be more generally applied in the utility industry. An agenda for further research will also be developed, if appropriate.

Another project is focusing on the development of an integrated technical approach to utility planning (RP2807). Called CHOICE, this approach consists of three steps: developing risk profiles of technology options, analyzing the effect of these options on a utility's corporate objectives (taking into account the uncertain business environment), and developing risk management approaches for combining options into risk-resilient strategies.

To be useful in practice, the CHOICE approach must consider the process issues associated with integrated planning as well as the technical issues. Thus EPRI expects that the findings of the planning-process research projects described above will play a major role in supporting the CHOICE project and ensuring that the finished product will be useful to individual utilities.

In summary, several projects in the strategic planning subprogram address aspects of the process of decision making and planning, and a significant number of research results will be reported in 1986. EPRI believes that this research will provide critical support to the utility industry at a time when its decision situations involve an increasing number of uncertainties and are very ill structured. In addition, the research findings will influence the type of quantitative tools developed by EPRI and by management science and operations researchers in general. *Acting Program Manager: Dominic Geraghty*

SOLID-WASTE ENVIRONMENTAL STUDIES

A major concern associated with the land disposal of utility solid wastes is the release and migration of solutes to groundwater. Protecting groundwater from contamination is a principal objective of regulations being developed under the Resource Conservation and Recovery Act, EPA's Groundwater Protection Strategy, the Safe Drinking Water Act, and various state and local rules. Requirements that affect waste disposal are of concern to the electric utility industry because it generates over 80 million tons of solid wastes annually. To decide when and to what extent control technologies should be applied, reliable predictions of the mobilization and environmental fate of leachates are needed. Actions based on a less than adequate understanding could result in controls that are either more or less stringent than required for safe disposal; in either case costs could increase for the utility industry. In response to this need, EPRI began research to develop methods for determining how the disposal of solid residues from fossil fuel combustion influences groundwater quality, and in 1983 this work was consolidated into the solid-waste environmental studies (SWES) project (RP2485).

The goal of SWES is to develop and validate methods (including new data) for predicting the release, transformation, transport, and ultimate fate of chemicals from utility solid wastes. Planned activities under SWES include evaluating existing predictive models, assembling interim models, and conducting experiments to quantify waste leaching behavior, physical transport, and chemical attenuation. In addition, a special study is quantifying the uncertainty associated with field measurement methods and groundwater sampling techniques. Over the longer term, researchers will develop improved geohydrochemical models and validate them with field data collected under the SWES project.

Leaching chemistry studies

To be able to predict waste solute concentrations in groundwater, we must first be able to predict the release (concentrations and duration) of solutes from a waste disposal site. Yet few data are available for making such predictions. The SWES project seeks to develop a mechanistic understanding of the processes that govern waste dissolution. Toward that goal A. D. Little, Inc., conducted a limited number of pilot studies to test the feasibility of using slurry batch experiments and elevated temperatures to quantify long-term leaching (RP2485-4). Three different waste types—coal ash, oil ash, and flue gas desulfurization (FGD) sludge—were leached, with and without leaching solution renewal, at either 20° or 90°C. The results (reported in EPRI EA-4215) indicate that simple washout, equilibrium sorption reactions, equilibrium dissolution-precipitation reactions, and rate-limited dissolution processes are involved in determining which chemicals are released.

In June 1985 Battelle, Pacific Northwest Laboratories initiated further studies on waste leaching chemistry (RP2485-8). One objective was to develop data on the reproducibility of EPA's extraction procedure (EP) and toxicity characteristics leaching procedure (TCLP). In round-robin testing completed last February, three laboratories evaluated the procedures on three fly ashes, two bottom ashes, and two FGD sludges. This testing has found that compared with the EP method, the new TCLP method generally yields higher concentrations in the extracts for the inorganic elements analyzed. Approximately 55% of these differences fall in the ±25% range; about 19% of them are 100% or larger in magnitude. The TCLP method is easier to implement and more precise than the EP method. A report on this study is scheduled for publication this summer.

Other work is under way to develop equilibrium and kinetic data for use in predicting waste leaching rates and waste interstitial solution concentrations for fly ash, bottom ash, scrubber sludges, oil ash, and fluidized-bed combustion wastes. These studies will use approximately 100 waste samples from some 40 power plants. The planned laboratory- and field-scale experiments will be conducted through 1991, and reports will be published as various parts of the research are completed.

Subsurface transport studies

Once waste solutes enter the subsurface environment, they are transported by advective and dispersive processes. Advection in groundwater systems is relatively well understood; dispersion, which can significantly affect solute concentrations, is not. To quantify dispersion in the subsurface environment, researchers need a better fundamental understanding of its causes.

Most groundwater solute transport models represent dispersion mathematically by using dispersivity coefficients, which are assumed to be constant and independent of the permeable media. Recent work indicates, however, that dispersion in groundwater most likely results from variations in the hydraulic conductivity of the permeable media and the intermingling of water flow paths. Dispersion appears to increase with distance of travel from the solute source, but this apparent increase and its relationship to the properties of the permeable media have not yet been quantified. EPRI EA-4190, which is a review of subsurface solute transport processes, presents details.

Under SWES two fundamental studies are focusing on dispersive processes. In the Macrodispersion Experiment (MADE), researchers from the Tennessee Valley Authority and the Massachusetts Institute of Technology are studying dispersion in the saturated groundwater zone (RP2485-5). By performing tracer experiments in a well-characterized aquifer, the researchers hope to relate dispersion to measurable physical properties of the subsurface environment so that proper predictive formulations can be developed. EA-4082 describes the experimental design.

A heterogeneous aquifer was selected for MADE in order to represent typical utility site conditions. The field site is located at Columbus Air Force Base in Mississippi in an area with regulated access. During 1985 soil coring, geophysical measurement, and pumping tests were performed to quantify the aquifer's characteristics, including the spatial distribution of hydraulic conductivity. Also, to aid in experimental design, simulations of the planned tracer injection were made with existing mathematical models. Seven tracers are to be injected in the aquifer, and monitoring of the plume's movement will continue for two to three years. A special gas chromatography–mass spectrometry probe system, developed in part under the SWES project, will be used for the direct determination of plume tracer concentrations in the field.

Dispersion in the unsaturated zone is being investigated by researchers from the University of California at Riverside in a study cofunded by Southern California Edison Co. (RP2485-6). Two sites in southern California, Etiwanda and Moreno, are being used. An analysis of data from previous tracer experiments (a steady-state bromide application at Etiwanda and chloride applications at both sites) has indicated that with downward seepage, dispersion increases with distance over at least the upper 3 m of the soil. A pilot tracer experiment is now being set up at the Moreno site, and full-scale experiments at both sites are to begin late this year. The depth to the saturated zone, about 100 m, is representative of dry conditions in the West, where unsaturated flow takes on greater importance.

Chemical attenuation studies

Besides the physical processes discussed above, chemical interactions with the groundwater and the permeable media can cause large changes (typically decreases) in solute concentrations. Some solutes, like aqueous lead, may undergo concentration decreases of several orders of magnitude when passing through less than 1 m of soil; others, like chloride, may undergo no measurable concentration decrease over distances of hundreds of meters. Most solutes experience soil-chemical interactions between these two extremes.

Which solutes will be removed from solution? To what extent will removal occur and under what conditions? How can it be reliably predicted? These questions are being addressed by Battelle, Pacific Northwest Laboratories in the SWES chemical attenuation studies (RP2485-3). The SWES data collected thus far indicate that chemical attenuation is due mostly to three processes: precipitation, coprecipitation, and adsorption. These processes have been shown to be highly dependent on the chemical characteristics of the groundwater and the soil materials (EA-3356).

Adsorption is important for solutes that do not readily precipitate and also, to a lesser extent, for some solutes that do precipitate. It is typically represented by a distribution coefficient (K_d), which is the ratio of the concentration of the adsorbed chemical to the concentration of the chemical in solution; higher K_d values indicate greater chemical attenuation.

The adsorption of solutes is strongly dependent on such factors as the solution's pH and ionic composition. SWES data on the adsorption of the leachate species chromate on a common soil constituent ($Fe_2O_3 \cdot H_2O$), for example, show that K_d increases as pH decreases (Table 1). The data also show that some of the common macroions compete with chromate for adsorption sites, thereby reducing chromate adsorption. These results indicate that K_d is not a constant and that a more sophisticated approach is necessary to properly model the chemical attenuation of solutes.

SWES research has also shown that chromate concentrations decrease because of the conversion of chromium(VI) to chromium(III) by very small amounts of reduced iron present in hematite and biotite, common soil minerals. Chromium(III) in the subsurface environment was found to be controlled by precipitation-dissolution reactions. Chromium hydroxide and chromium iron hydroxide were identified as the two solid compounds important in keeping chromium(III) concentrations at levels well below the drinking water standards in the pH range of 5 to 10.

A complete thermodynamic and kinetic data base has been developed for chromium (EA-4544). Several soils from utility sites have been used in the experiments to ensure that the results have practical application. Similar data bases are being developed for arsenic, boron, cadmium, selenium, vanadium, and zinc. Several reports will be published during the course of this research, which is scheduled for completion by the end of 1990.

Table 1
CHROMATE ADSORPTION ON AMORPHOUS IRON OXIDE

	Distribution Coefficient (K_d)	
Solution pH	Simple Solution*	Complex Solution†
5.65	478,600	18,600
6.94	112,200	5,370
7.80	6,600	130

*0.1 molar $NaNO_3$ solution.
†Solution with Na, NO_3, Ca, SO_4, and CO_2 ions.

Field sampling methods

Model calibration, validation, and assessment at specific waste disposal sites all require sampling and analysis of the subsurface environment. Sampling is generally more costly for groundwater than for surface waters because of the cost of installing wells. The analysis of groundwater solutions is also more difficult, in part because of higher total dissolved solids concentrations. Further, groundwaters are often supersaturated or undersaturated with respect to atmospheric gases. It has long been suspected that the sampling methods used may significantly alter what is measured. To date, little effort has been devoted to quantifying the uncertainties introduced by sampling methods.

The first phase of the SWES research in this area (RP2485-7) focused on quantifying the errors in groundwater quality measurements caused by sampling devices (EA-4118). The researchers found that some commonly used sampling devices and procedures introduce enough oxygen to convert dissolved iron(II) to iron(III), which is relatively insoluble and rapidly precipitates from solution. Solutes, particularly metals that are regulated, either coprecipitate with the iron(III) or adsorb onto the freshly formed amorphous iron oxide precipitates; thus the measured solution concentrations of these chemicals are reduced.

Various sampling and measurement techniques are being field-tested in a 30- by 30-m coal ash test cell at the Montour power plant of Pennsylvania Power & Light Co., which is cofunding the research. Preliminary results indicate that both tensiometers and neutron probes provide reliable measurements of the infiltration of moisture in an ash landfill. A report on this work will be published later this year.

Interim model development

The models being improved under SWES will be used to predict the groundwater concentrations of solutes leached from utility solid wastes. SWES researchers have reviewed and tested about 100 existing groundwater models; the results are presented in EA-3417. Efforts are now focused on the development of an interim model to simulate both the hydrologic and geochemical behavior of utility waste leachates.

Called FASTCHEM, this interim model is being developed by Battelle, Pacific Northwest Laboratories and is scheduled for completion in late 1987 (RP2485-2). FASTCHEM will simulate the flow of water and the transport of solutes through saturated and unsaturated subsurface environments. The hydrologic component of the model uses a two-dimensional finite-element solution technique. Groundwater flow will be routed along stream tubes. Chemical reactions will be simulated by using a geochemical subroutine. The coupling of the hydrologic and geochemical routines represents a major technical effort. The stream tubes will be divided into series of discrete cells for modeling the geochemical reactions; an advective transport step will follow. Dispersive transport will be simulated by using a Markov model. The probability distribution function can be selected to accommodate either Fickian or non-Fickian dispersion representations.

In March 1986 EPRI released an IBM PC code called MYGRT for use in analyzing solute migration in groundwater (EA-4543). Screening studies with MYGRT can determine if more-detailed analysis is necessary. Developed by Tetra Tech, Inc. (RP2485-1), MYGRT contains both a one-dimensional code and a two-dimensional code. A prerelease version was tested by several utilities, and recommended improvements have been incorporated into the final version.

In conclusion, the solid-waste research of EPRI's Environmental Physics and Chemistry Program has produced results that are already being put to use by the utility industry and by researchers and regulators. A total of 29 reports have been published to date. Two technology transfer seminars have been held, and a third is scheduled for October 1986. *Project Managers: Ishwar P. Murarka and Dave A. McIntosh*

R&D Status Report
NUCLEAR POWER DIVISION

John J. Taylor, Vice President

RELIABILITY-CENTERED MAINTENANCE AT NUCLEAR PLANTS

The nuclear power industry is continuously striving to improve plant reliability and availability without compromising stringent safety standards. Reliability is manifested by the extent to which operations are continuous and trouble-free; availability is evidenced by a low level of unscheduled downtime. Improvements in design, in operating procedures, in technical specifications for operation, and in maintenance are some of the ways in which reliability and availability can be positively affected. Recent attention has focused on improving strategies for preventive maintenance (PM), which is maintenance performed at regularly scheduled intervals to prevent failures, to detect incipient failures, or to check for hidden failures in off-line systems.

A PM approach used successfully by the airlines and the military is reliability-centered maintenance (RCM). Simply stated, RCM is a systematic consideration of system functions and the ways in which functions can fail, plus a priority-based consideration of safety and economics that identifies applicable and effective PM tasks.

A 1984 EPRI study identified RCM as one of seven candidate areas for technology transfer from commercial aviation to the nuclear power industry (NP-3364). Using RCM, the airlines had no increases in unit maintenance costs over a 16-year period despite increases in the size and complexity of the aircraft they operated. And during the same period, the airline safety record steadily improved. EPRI's study concluded that the airlines' control of maintenance costs and their improving safety record were due in large measure to the systematic identification of applicable (i.e., it works) and effective (i.e., it's worth the cost) PM tasks that result from the RCM process.

EPRI and its utility advisory boards recommended that the usefulness of RCM be evaluated in trial applications at selected nuclear power plants. Florida Power & Light Co. (FPL) and Duke Power Co. were the hosts for two pilot applications. The contractors were Los Alamos Technical Associates, American Management Systems, and Saratoga Engineering Consultants.

The RCM technique

The RCM process comprises three major activities.

- Identifying functions and functional failures
- Establishing the importance of functional failures and failure modes (by using a decision logic tree)
- Defining PM tasks, but with the specific objective of following the established priorities (selecting only those PM tasks that are both applicable and effective)

The RCM approach (Table 1) is implemented in five basic steps: (1) information collection, (2) identification and partition, (3) requirements analysis, (4) PM task selection, and (5) packaging.

Information collection (step 1) is the gathering of system design and operation documentation, existing PM procedures and practices, corrective maintenance records for the system, and information related to failure experience with the system and with other, similar systems. The latter information is of particular value in highlighting areas where new or improved PM tasks can have significant effect.

Identification and partitioning (step 2) requires that system boundaries be identified and that inputs and outputs across the boundaries be defined. Each system is then separated into functional subsystems, which ensures that appropriate functions and related functional failures are clearly distinguished as inputs to succeeding steps.

The requirements analysis (step 3) is the heart of the RCM process. In the analysis, functionally significant items are identified, a functional failure analysis is performed for each item, and dominant failure modes associated with these failures are established in a failure modes and effects analysis. Dominant failure modes are those that occur frequently

Table 1
RCM IMPLEMENTATION STEPS

1 Information Collection	2 Identification and Partition	3 Requirements Analysis	4 PM Task Selection	5 Packaging
Identify RCM analysis team	Describe systems	Identify functionally significant items	Apply RCM decision logic	Compare with existing tasks
Identify data sources	Identify constituent system elements	Define functions	Identify potential PM tasks	Detail task instructions
Collect/compile data	Define zonal locations (if necessary)	Define functional failures	Select applicable and effective tasks	Revise task schedules
	Define system boundaries and interfaces	Identify dominant failure modes or functional failures	Establish task intervals	Install revised plan
		Establish cause-effect data	Identify design modifications	Audit
				Pursue redesign options

or are so injurious or costly that they must not be allowed to occur at all, at least insofar as that is possible. In addition, the dominant failure modes must be identified at a level at which a preventive task can be performed (an emphasis that is basically different from that in the design process).

An RCM decision logic tree is used for each dominant failure mode in order to select the PM tasks (step 4). By using the decision logic, each dominant failure mode is addressed by an appropriate PM task, by a design change, or by judging the failure mode to be acceptable. The process specifies (1) if the PM task should be done at a fixed interval, for example, time or cycles (time directed); (2) if it should be done at some predefined level of equipment performance or condition (condition directed); or (3) if a surveillance or failure-finding task is needed.

In step 5, the PM tasks are packaged; that is, they are defined in detail sufficient for their implementation into actual maintenance procedures.

RCM applications

The first application of RCM was in the component cooling water systems (CCWSs) of FPL's Turkey Point units 3 and 4 at Florida City, Florida (NP-4271). The CCWS removes heat from plant components during normal operation, as well as after potential accident-initiating events. CCWS was selected for the pilot study for two reasons: PM tasks that already existed involved several CCWS maintenance areas—electrical, mechanical, and instrumentation and controls. Further, the corrective maintenance (CM) load on the systems had been high. These high levels of PM and CM indicated the possibility of major benefits as a result of an RCM effort.

All five steps of the RCM procedure were completed for the CCWSs at the Turkey Point stations. The pilot study identified 180 functional failures from 66 separate functions performed by the system; this, in turn, generated about 350 dominant failure modes, which were reduced (on the basis of no significant safety or productivity effect) to 50 for analysis by means of the decision logic tree. The study recommended 24 tasks that differed from the existing ones. Of the tasks recommended, 6 were time directed (TD), 7 were condition directed (CD), 4 involved failure finding (FF) and 7 suggested design changes. A project team then drafted changes to the Turkey Point plant procedures for the TD and CD preventive maintenance tasks that were identified. This package of suggested PM changes will be a part of the evaluation of the plant PM program now under way at Turkey Point.

The application of RCM to the main feedwater system (MFWS) at Duke Power's William B. McGuire station, north of Charlotte, North Carolina, was begun near the end of the Turkey Point pilot study. The MFWS at McGuire had recently been modified in response to operational problems and corrective maintenance early in the plant's life. The RCM pilot study team investigated the system as it was before those modifications were made. The results of this RCM application (although not final at the time of writing) identify 22 possible CD tasks and 28 FF tasks. In addition, the study team recommended possible plant changes in two areas, one of which had been implemented earlier independently of the RCM study. Preliminary comparisons of the recommended RCM tasks and the current PM tasks, as identified by interviews of plant personnel, indicate that many of the RCM tasks are not now being addressed. Of the RCM-identified tasks that were already covered by current PM, the RCM team recommended that 25% be changed from TD to the more effective CD tasks.

Thus, it appears that the RCM process not only identified the major elements of the current PM program at the McGuire station but that it also developed desirable candidate CD tasks as replacements for existing TD tasks. The RCM process also verified the need for action in areas in which the plant is known to have been modified.

In summary, the RCM process provided means of achieving the same PM program in a potentially more cost-effective manner, and it also suggested two design changes and additional FF tasks that concern the prevention of operational surprises. These trial applications demonstrate that RCM can be a valuable part of an overall plan to develop or evaluate a PM program at a nuclear power plant. Because RCM investigates dominant failure modes, it can help eliminate ineffective tasks, often changing costly time-directed tasks to less frequent condition-directed ones and identifying missing tasks that can prevent significant failures.

With the completion of these pilot studies, the way is clear for further applications of RCM. The FPL pilot application is reported in NP-4271; the Duke Power application report is in preparation. These EPRI reports document in detail the analyses, including system descriptions, analysis worksheets, and specific recommendations. The reports make possible a thorough evaluation of RCM by prospective utility users. In addition, the reports point out practical considerations and limitations of RCM, including a way to select systems for which RCM is most likely to be cost-beneficial and the importance of involving plant personnel in the RCM analysis process. *Project Manager: John Gaertner*

CHEMICAL CLEANING UPDATE

EPRI and the Steam Generator Owners Group (SGOG) have been working to resolve steam generator problems since 1977. In a recent major accomplishment, Northeast Utilities used a slightly modified version of an SGOG-developed chemical process to clean the sludge pile regions of the steam generators at Unit 2 of the Millstone Nuclear Power Station. The cleaning removed harmful corrosion products that accumulate in steam generators during normal operation. The Millstone cleaning by Northeast Utilities was the successful climax of a seven-year, multimillion-dollar SGOG-sponsored laboratory and mockup testing project. As a result of that work, utilities now have an additional tool with which to combat steam generator degradation.

The impurities and corrosion products that accumulate in steam generators contribute to corrosion-induced damage on the secondary side of pressurized water reactor (PWR) generators. Corrosion products form in the steam, feed, and condensate system, and then they are transported by the feedwater into the steam generator. There they are deposited on generator tubes and support structures. Several hundred pounds of this sludge can be deposited each year. The sludge in mixed-alloy systems consists principally of magnetite (Fe_3O_4), copper, and copper oxides (CuO and Cu_2O). Chemically active impurities from such sources as condenser cooling water leakage concentrate in the sludge and corrode steam generator tubes and support structures. The result can be stress corrosion cracking, intergranular attack, tube deformation (denting), wastage, and tube pitting. Removal of the sludge can significantly improve steam generator reliability.

Water chemistry improvements at many utilities have reduced the amount of sludge entering steam generators, but previously deposited sludge, coupled with the smaller amounts still entering the generators, remains a serious problem at many plants. Water-lancing to remove the sludge can be effective in removing the softer deposits, but much of the harder sludge is unaffected by lancing. Chemical cleaning can, however, complement and increase the effectiveness of sludge removal.

To deal with this problem, SGOG developed a two-step chemical cleaning process that uses the chelating agent ethylenediaminetetraacetic acid (EDTA). Table 2 lists the constituents of the generic sludge-removal sol-

Table 2
SGOG GENERIC SLUDGE REMOVAL SOLVENTS

Iron Oxide Solvent	Copper Oxide Solvent
200°F	100°F
10% EDTA*	5% EDTA
1% hydrazine	2–3% hydrogen peroxide
0.5% CCI-801†	Ammonium hydroxide to pH 7.0
Ammonium hydroxide to pH 7.0	Ethylenediamine to pH 10

*Ethylenediaminetetraacetic acid.
†Nonproprietary corrosion inhibitor.

vents for iron and copper. Before applying these solvents, the utilities generally perform site-specific qualification testing.

Cleaning preparation

Pitting of steam generator tubes at Millstone Unit 2 was first detected in 1981 at the end of the fourth fuel cycle. The pitting was limited to the region below the first tube support within the sludge pile area. Water-lancing was only partially successful in removing the accumulated sludge, and plans were made to use a chemical cleaning process. The SGOG generic solvent was selected as the basis for qualification, followed by significant utility-sponsored, site-specific qualification. Ultimately, the SGOG iron solvent and a slightly modified version of the SGOG copper solvent was used at Millstone.

Northeast Utilities was the overall program manager and sponsor for the Millstone cleaning. Supporting contractors were Combustion Engineering, Inc., for solvent qualification, onsite corrosion monitoring, laboratory analyses, and cleaning-process consultation; Pacific Nuclear Services for hardware procurement and installation assistance, solvent mixing, solvent handling and recirculation, and the process instrumentation and control system; and London Nuclear Associates for waste disposal.

The chemical cleaning system used at Millstone was designed to provide for (1) primary-side recirculation for temperature control, (2) chemical mixing and storage, (3) secondary-side recirculation, (4) waste holdup and demineralized water storage, (5) vent collection/scrubber, and (6) rinse waste cleanup by demineralization.

All system materials were qualified in the materials testing programs. Separate recirculation systems were used for the primary and secondary sides of the steam generator, thus allowing other outage activities, such as refueling, to proceed during the chemical cleaning. Temporary dams were used in the hot and cold leg nozzles of the steam generator channel heads. Steam generator heat-up and cool-down times were also minimized by using the primary-side recirculation system.

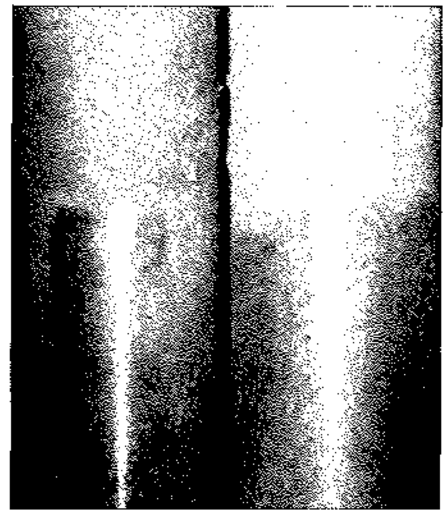
A chemical mixing system was provided for preparing and establishing the temperature of the iron and copper solvents, as well as the demineralized water rinse and passivation solutions prior to their introduction into the steam generators. Measured volumes of solution were prepared in the mix tanks as a backup to the steam generator level indication to control the volumes injected into the recirculation system. In this way, the solvent levels in the steam generator were at all times controlled and maintained below the first tube support. The cleaning solvents, rinse, and passivation solutions were recirculated through the steam generator, using the secondary-side recirculation system. An air-operated pump was used to drain residual solvent from the steam generators and to provide for solvent removal should an electrical failure occur. Process control was provided by an automatic data acquisition system that monitored and recorded critical process variables. Automatic circuits shut down the recirculation pumps on high and low pressure, as well as on high steam generator level.

Around-the-clock efforts were begun several months before the actual cleaning. During the early stages of equipment installation and testing, several hundred workers were required; during the actual cleaning operation, however, the manpower needs were significantly reduced.

Cleaning

The chemical process, consisting of recirculating the iron and copper solvent described previously, was applied to the two steam generators in succession. Two iron-solvent stages were applied to both generators. Six copper-solvent stages were applied to the first generator and four to the second. Samples of the solvents were analyzed for copper and iron (as appropriate), in addition to several other parameters, to determine when each step had progressed to completion; that is, when no further significant increase in iron or copper in the solvent was observed. About 209 hours were required to clean the first generator, whereas the second required only about 103 hours from the initial rinse to the prepassivation rinse. The cleaning of the second generator was accomplished in less time than the first because fewer copper-solvent stages were used (four instead of six) and because experience and confidence in the process and equipment had been gained in cleaning the first unit.

Figure 1 Steam generator tubes after chemical cleaning. The cleaning removed over 550 lb (250 kg) of corrosion products from two steam generators.



The corrosion products removed by the solvents included iron, copper, zinc, and nickel. About 310 lb (141 kg) of these substances were removed from the first generator and about 257 lb (117 kg) from the second (as determined by analyses of the solvents). Several cleaned steam generator tubes are shown in Figure 1.

Approximately 50% of the corrosion products removed by the chemical cleaning was copper metal. The cleaning process generated about 1200 gal (4.5 m^3) of waste for each solvent-and-rinse stage. The total volume of solvent liquid wastes that had to be processed was 24,000 gal (90 m^3). Rinse wastes were reused after cleanup by ion-exchange.

The chemical cleaning of the two steam generators of Millstone Unit 2 was successful in removing over 550 lb (250 kg) of sludge and demonstrated the effectiveness of a large-scale chemical cleaning effort based on the SGOG-developed solvent process. As a result, several utilities are planning similar steam generator cleaning projects. *Project Manager: C. Lamar Williams*

New Contracts

Project	Funding and Duration	Contractor/ EPRI Project Manager
Advanced Power Systems		
Quantification and Verification of Enhancements to the PROMOD Combined-Cycle Module (RP2699-7)	$46,000 12 months	Energy Management Associates, Inc./*A. Lewis*
Underground Coal-Gasification Test (RP2735-01)	$150,000 34 months	Gas Research Institute/ *N. Hertz*
Depolymerization of Coal (RP8003-3)	$50,000 10 months	Lawrence Berkeley Laboratory/*L. Atherton*
Coal Combustion Systems		
Boiler Tube Failure Manual (RP1890-7)	$220,300 22 months	General Physics Corp./ *B. Dooley*
In-Place Inspection of Turbine Blades (RP1957-6)	$126,000 13 months	Reinhart & Associates/ *J. Scheibel*
Technical and Economic Guidelines for Evaluating Power Plant Water Management Options (RP2114-5)	$237,000 14 months	Sargent & Lundy Engineers/*W. Micheletti*
Field Testing of Behavioral Barriers for Cooling-Water Intake Systems (RP2214-6)	$474,400 14 months	Lawler, Matusky and Skelly Engineers/ *W. Micheletti*
Electrical Systems		
Evaluation of Active Filter Concepts for HVDC Converters (RP2115-15)	$34,200 12 months	University of Minnesota/ *S. Wright*
Development of Advanced Float-Zone Silicon Material (RP2737-4)	$613,000 25 months	Westinghouse Electric Corp./*H. Mehta*
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Project	Funding and Duration	Contractor/ EPRI Project Manager
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Nuclear Power		
Effects of Decontamination on BWR Fuel (RP2296-12)	$607,100 23 months	Babcock & Wilcox Co./ *J. Santucci*
Effects of Decontamination on BWR Fuel (RP2460-1)	$200,000 9 months	Babcock & Wilcox Co./ *J. Santucci*
PWR Pilot Plant Life Extension Program (RP2643-1)	$255,300 24 months	Virginia Power/*M. Lapides*
BWR Pilot Plant Life Extension (RP2643-2)	$150,000 24 months	Northern States Power Co./*M. Lapides*
LMFBR Technical Integration Studies (RP2658-6)	$520,200 13 months	Westinghouse Electric Corp./*D. Gibbs*
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EPRI Project Manager: P. Lyons

HPOF: Transmission System Economic Evaluation Program
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