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COAL AND NUCLEAR POWER: ILLINOIS' ENERGY FUTURE

PROCEEDINGS OF THE

TENTH ANNUAL ILLINOIS ENERGY CONFERENCE

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FOREWORD

The Tenth Annual Illinois Energy Conference, held in Chicago, Illinois, in October 1982 was sponsored by the Energy Resources Center, University of Illinois at Chicago; the U.S. Department of Energy; the Illinois Energy Resources Commission; and the Illinois Department of Energy and Natural Resources.

The theme for the conference was "Coal and Nuclear Power: Illinois' Energy Future." Selection of the topic was based on two major observations:

(1) Illinois has the largest reserves of bituminous coal of any state and is surpassed in total reserves only by North Dakota and Montana

(2) Illinois has made a heavy commitment to the use of nuclear power as a source of electrical power generation. Currently, nuclear power represents 30% of the electrical energy produced in the State. The primary objective of the 1982 conference was to review these two energy sources in view of the current energy policy of the Reagan Administration, and to examine the impact these policies have on the Midwest energy scene. The conference dealt with issues unique to Illinois as well as those facing the entire nation.

As in the past, the planning committee was composed of representatives from energy industries; local, state, and federal agencies; industrial and government research laboratories; public interest groups; and universities. This group was organized early in 1982 and was responsible for developing the final program and for the selection of speakers. They are listed on the preceding page.

Appreciation is extended to the outstanding speakers whose papers appear in this publication and who are responsible for the quality of the program. A special note of thanks is extended to the keynote speakers, Alvin L. Alm, Director, Harvard's Energy Security Program; S. David Freeman, Managing Director, Tennessee Valley Authority; Victor Gilinsky, Commissioner, Nuclear Regulatory Commission; Jan W. Mares, Acting Under Secretary, U.S. Department of Energy; Edward S. Miller, Vice President, Synthetic Fuels Corporation; and The Honorable Charles H. Percy, United States Senate.

In addition to the planning committee and speakers, I would like to acknowledge the support and encouragement of the sponsors and the assistance of the session co-chairmen who moved the program along smoothly.

I also want to express appreciation to the clerical staff of the Energy Resources Center, especially Claudette Eldridge and Marion B. Deloney for their help in coordinating the many tasks involved in a program of this kind and to the staff of the Publications Office Word Processing Center who did a fine job in putting this book together. Last but not least, I thank my assistant, James Wiet, who contributed greatly to the organization of the conference.

I hope the proceedings of this year's conference will be useful in providing information on major policy issues currently facing the State of Illinois and the nation.

James P. Hartnett, Chairman
Planning Committee

OPENING REMARKS

Robert H. Bauer
Manager, Region V
U.S. Department of Energy

Tenth anniversaries provide irresistible occasions for reflective backward glances. This is particularly true for this 10th Annual Illinois Energy Conference. Since 1972, the nature of this nation's energy problem, and our perceptions of it, have changed more dramatically than most attendees at that first conference could have guessed.

Participants in that conference, for example, would have been concerned with such energy issues as:

- Could adequate electrical capacity be assured to meet the historical 7% growth rate experienced through the 60's and early 70's?
- Was the long decline in Illinois coal production irreversible in the face of competition from so-called clean-burning fuels such as oil and gas, and nuclear power?
- Would adequate supplies of uranium be found in the U.S. to sustain the projected 1,000 commercial reactors expected to be operating by the end of the century?
- Would expected fuel reprocessing and uranium enrichment capacity be available to help meet the expected demands on uranium resources?
- Could the nation's modest, but growing, dependence on imported oil present real economic or political problems?

While it is uncertain as to what extent those issues actually dominated the consciousness of those conference attendees ten years ago, these questions certainly were at the forefront. The events of the following decade demonstrate how poorly we have anticipated the future and how difficult it is, with any great accuracy, to predict even near-term energy trends. The political, economic and social fabric of our times weaves a pattern that has proven too dark and complex to permit easy or accurate forecasts.

At this conference, other speakers will address this issue; I raise it in these introductory remarks not to belittle our perceptions of a decade ago, but to suggest that we enter into this conference with minds open to the potential of a future equally full of surprises. Experience has shown us that a good deal of those surprises will be unpleasant, but

certainly not all. We have, after all, discarded the cast iron linkage between growth in Gross National Product and energy that was broadly held with nearly religious conviction not too long ago. And the elasticity of demand for energy in response to price has startled the world, including the OPEC nations, whose crystal ball has proven as cloudy as our own.

In many respects, the participants who preceded us by a decade were right on target. For example, consider their emphasis on the importance of coal and nuclear power to the State of Illinois and the nation. The last ten years have served to sharpen our perception of the vital role these energy systems play in our present and must, increasingly, in our future. So I feel it is particularly appropriate that the focus for this conference is on Coal and Nuclear Power: Illinois' Energy Future.

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KEYNOTE ADDRESS

Illinois: The Key to America's Energy Transition

The Honorable Charles H. Percy
U.S. Senate

On a number of my trips downstate last summer, I was repeatedly impressed by the bumper crop of corn being produced this year by Illinois farmers. But almost everywhere I went, this good news was treated as bad news -- because the harvest this season is so large, farm prices are depressed and we simply don't have enough places to store much of the corn.

Coming up with a way to convert this negative back into something positive was a pleasant challenge. Why not use the surplus of one resource -- corn -- to respond to a shortage in another -- energy? We are not talking about food versus fuel -- we are talking about making productive use of something that would otherwise go to waste.

Knowing that ethanol from corn has been successfully used as an octane booster for today's automobiles, I discussed this idea with my colleague, Alan Dixon and together we introduced a bill to make it a reality. I am pleased to report that our bill, which makes it possible for the Department of Agriculture to convert at least 32 million tons of surplus corn into ethanol, was passed by the Congress and the President will soon sign it into law.[1]

In the sixteen years I have been in the Senate, I have rarely seen a bill move so swiftly and with such overwhelming bipartisan support. It shows just how much enthusiasm there is for creative solutions to our energy problems -- especially solutions which are found right in our own back yard. From coal to conservation, from nuclear power to solar energy, there is a great deal we can do in Illinois and throughout the nation as we make the inevitable transition to a new energy age.

During the 1970's, we confronted one energy crisis after another -- the Arab oil embargo, natural gas shortages, and a major coal strike -- all with a significant cost to our economy. The past decade has taught us <u>not</u> to become overly reliant on any one source of energy -- whether it be oil, coal, nuclear or anything else. This is why, as Chairman of the Senate Subcommittee on Energy, Nuclear Proliferation and Government Processes, I have fought hard for the

[1]Signed by President Reagan on October 21, 1982.

kind of balanced energy policy that people in Illinois and elsewhere in America want to see.

As you know, the Reagan Administration recently submitted an energy reorganization proposal to Congress. I have supported much of what the President has accomplished in energy policy, and I would like to support his reorganization plan. But I have made it quite clear that before this energy reorganization legislation can move forward with my support, the Administration must show a greater commitment to the diversified energy future which is imperative for Illinois and the nation as a whole.

Coal is a good place to start. Illinois has enormous reserves of bituminous coal, more than those of any other state. There are currently 45,000 people in Illinois working in coal-related jobs. There has never been any doubt that coal can be competitive with nuclear and other resources as a source of generating electricity Recently, the Department of Energy issued a report indicating that coal-fired electricity generation for new plants beginning service in 1995 will be in a virtual dead heat with nuclear generation in most regions of the country. The question remains whether Illinois coal will command its fair share of the coal market.

There is no doubt that the high sulfur content of Illinois coal has limited its marketability in the past. But I am delighted to say that technological advances in recent years have proven very promising. On March 22, 1982 I dedicated a new pollution control device at Argonne National Laboratory that permits burning -- within EPA standards -- of high-sulfur Illinois coal. Breakthroughs like this give me the faith in our ability to employ new technologies to increase the use of Illinois coal -- America's equivalent of Arabian oil -- without abandoning the environmental standards of this country. Last year our coal export conference in Carbondale showed that the long-range prospects for Illinois coal exports are promising indeed. We all know how sluggish the world coal market has been recently. However, I am convinced that demand for our coal will re-emerge as soon as we rebound from our global economic doldrums. As Chairman of the Foreign Relations Committee, I take every opportunity to remind foreign Ministers how economical our coal -- and our coal transportation system -- can be for their customers back home, especially in the cement industry.

After coal, our next most significant local form of energy in Illinois is nuclear power. Although I have often criticized the U.S. Energy Department for overemphasizing this technology at the expense of

others, I am the first to acknowledge the contributions that nuclear power has made in Illinois -- for example, how it has provided relatively inexpensive power, allowing Illinois industries to prosper. With reductions in electricity demand and the increasing cost of new plant construction and financing, however, the economics of new nuclear generating plants have changed. There is a growing consensus that conservation is often more cost-effective than building new power plants -- nuclear or otherwise.

The nuclear industry is also facing a "crisis in public confidence" -- some of which is imagined and out of proportion to the true risks involved, but much of which is grounded in very real environmental and safety concerns. This is exemplified by the current debate over the disposal of nuclear waste.

I, along with Senator Glenn of Ohio, introduced a nuclear waste bill over two years ago. Many of the provisions of this bill have been adopted in the legislation and are now close to adoption. But along the way, new and undesirable provisions have been added. The Senate bill calls for the establishment of federally-owned and operated Away-from-Reactor (AFR) facilities for the storage of spent nuclear fuel. I see no reason now for the federal government to take over what should be a private sector task. Indeed, wise utilities have moved ahead in expanding their onsite storage through reracking and other alternatives. In addition, dry storage may soon greatly enhance the potential for onsite storage at an even more reasonable cost.

I am concerned that the very possibility of the federal government picking up this responsibility will discourage serious private sector efforts to find permanent disposal for nuclear waste. We cannot allow these temporary pools to become permanent respositories. The immediate object of my concern is the Morris, Illinois storage site -- one of the three likely candidates for a government operated spent nuclear fuel storage facility. Although the safety record at the General Electric facility has been impeccable to date, the people in the Morris area are understandably nervous about their comminity becoming the "dumping ground" of the nation.

I, along with my colleagues from other potentially affected AFR states, introduced an amendment to the Senate nuclear waste bill to eliminate this possibility. Our amendment failed by a narrow margin, but the version of the bill now before the House would prevent the Morris facility from becoming

a federally-owned AFR facility. I am doing what I can to make sure this House version prevails.

I am hopeful that a bill can be passed during the lame duck session year, but -- whatever Congress does or does not do -- I would like to see utilities getting on with the business of expanding onsite storage, while the federal government gets on with the business of developing safe permanent disposal.

There are a number of other energy resources with potential to contribute to Illinois' energy and economic future. I talked earlier about alcohol fuels. Illinois also has small but significant oil and gas reserves. There was record drilling last year in Illinois wells, with over 7,000 individuals involved in oil and gas production in the state. Similarly, there is potential in the state for development of hydroelectric generation, wind power for small uses, and the recycling of municipal garbage.

One of the most under utilized energy resources here in our state in our human energy -- such as the ingenuity found in the Illinois research community. And I am doing all I can to take advantage of this valuable resource by maintaining our commitment to important energy research and development. In March of this year, I held a field hearing of my Energy Subcommittee at Argonne National Laboratory, focusing on the critical importance of Argonne, Fermi, and other Midwest laboratories. I recently received some very promising news from Reagan Administration officials about the future of Argonne -- negotiations on extending the University of Chicago contract to operate the lab will soon be underway.

Human ingenuity can contribute not only to the development of new resources, but also to the more efficient use of existing energy supplies -- a fact particularly apparent in Illinois. A hearing I held in Washington a year ago highlighted the many community-level conservation efforts in Springfield, and other cities and towns throughout the state -- and, I should add, in businesses large and small. I am particularly pleased to see so many energy managers from companies here today. Ten years ago, most all corporate officials thought an energy manager was a labor productivity expert.

In spite of the great advances made over the past ten years, the potential for energy conservation is far from being fully exploited. Back in 1977, Hubert Humphrey and I founded the Alliance to Save Energy, a coalition of business, labor, and citizens' groups dedicated to increasing the efficiency of energy use in the United States. At that time,

America was importing more than 8 million barrels of foreign oil every day. Since then, we have demonstrated an amazing ability to do something about that. Through increased energy production and especially conservation, we have cut our oil imports roughly in half. But these impressive figures should not be misread -- our current recession explains at least a part of these results. But as our economy gets moving again, as I am confident it will, we must not return to our wasteful ways of the past. Through a more efficient use of energy, we can sustain economic growth without causing shortages and another surge of oil and gas price increases.

The auto industry offers a good example of this resiliency. When Americans return to new car showrooms, they will be buying the most fuel-efficient autos in our Nation's history. My wife Loraine and I recently bought two such cars -- a Chyrsler and a mid-sized Mercury -- right off Illinois assembly lines, and I must say that American cars have never before been better.

A recent study by Oak Ridge National Laboratory shows that through the use of conservation technologies in the auto, construction, and other industries during the next forty years we will be able to produce over three trillion dollars worth of savings. This breaks down to roughly 100 billion dollars in savings a year -- 100 billion dollars which will be freed up to stimulate additional economic development and, of course, create more jobs.

Conservation may be particularly important to major Midwestern industries which tend to be highly energy intensive. But although prices certainly stimulate conservation measures in these industries, major long-term investments in energy efficiency improvements have yet to be made.

The same is certainly true for homes and apartments throughout Illinois. I have always encouraged utilities to help consumers find low-cost means of using energy more efficiently. I know the Thompson Administration has advocated this in its state energy plan. There is a great deal we can accomplish in this area by working together with industry and utilities as a team.

I have to be candid with you -- over the past two years I have been deeply disturbed by the Department of Energy's attitude toward conservation. Conservation has been consistently downgraded in budgetary priorities, personnel actions, and public actions. Almost a year ago, I asked Secretary Edwards to propose new, market-oriented strategies

for energy conservation. So far, I have seen no new ideas emerging from DOE in this vital area. This has to change, and I will continue to make my views known until I see some real progress in this area.

There is one positive note, however. Additional money may soon be available for states to stimulate additional conservation efforts. Recently, I wrote Secretary Edwards, urging him to use the states as a mechanism for distributing over 200 million dollars collected from past oil company overcharges, and currently in escrow at the Department of Energy. This could provide the seed money for state's energy efficient investments, which can save us even more money over time.

As Illinois works hard to conserve energy, especially in an area of rising natural gas prices, I will do what I can to see that we are not unduly burdened with unnecessary costs. Along with several others in the Illinois congressional delegation, I am presently trying to block a proposed pass-through of the cost of Algerian liquified natural gas, or "LNG", to Illinois customers. As many of you know, out-of-state pipeline companies made a bad decision to buy this very expensive gas. While they made the decision in good faith, it has turned out to be a very unfortunate and costly one for Illinois. There is nothing unusual about a company making a poor investment -- it happens all the time. But in this case, they want to make us -- Illinois consumers -- pay for their mistake.

Today, there is an abundant supply of natural gas in the marketplace, at prices one-third or less what this Algerian LNG would cost us. Three weeks ago, I wrote to DOE Secretary Edwards expressing my view that Illinois consumers -- and Illinois utilities -- should not be stuck holding the bag for the investment blunders of others.

Even if we are successful in blocking this pass-through of excessive costs for LNG, natural gas prices are still headed up this winter. Our federal weatherization and low-income energy assistance programs will be more important than ever. I will keep a close watch over these programs to make sure that the money is released in a timely manner and to make sure that the poor and the elderly can afford to keep their houses warm this winter.

Although natural gas is of immediate concern this winter, let's not forget the fuel that precipitated the energy crisis in the first place -- and that, of course, is oil. Despite the relatively slack oil market over the past year, we simply cannot

be lulled into believing that there will be no future disruptions. Long-term prospects for declining world oil production -- and the political instablility of the Middle East -- make the 1980's a potentially dangerous decade. I occasionally see reports very critical of what the Reagan Administration has or has not done to bolster our emergency preparedness -- and I could not disagree more strongly. In my view, we have never before had a President who takes the problem more seriously.

For several years now, I have given this issue a very high personal priority. I led the President's fight in the Senate against the adoption of the same old emergency petroleum allocation program that got us in so much trouble the last time around. I have worked hand-in-hand with the Administration to fill the Strategic Petroleum Reserve at an unprecedented rate, and to make sure that the needs of the agricultural community and others can be met through use of this reserve in an emergency. One solution I have proposed would be to develop regional reserves -- possibly including alcohol fuel reserves -- in the Midwest and other areas likely to be most hard-hit by any oil shortage.

I am also working closely with the Administration to ensure that our energy infrastructure is physically secure -- in other words, to make sure that the flow of oil, gas, or electricity in Illinois or any other state will never be seriously disrupted by terrorists or saboteurs. To the extent this may be a risk today, I want to assure you that -- if I have anything to say about it -- it will not be a risk tomorrow.

So there is much for us to be proud of, but still much to be done. Arm-in-arm with Governor Thompson and our fine Congressional delegation, who have helped in so many ways, we are doing what we can to make Illinois' energy future a bountiful one.

Illinois is in many respects a microcosm of the United States. An energy policy that works for us -- an energy policy that helps rebuild our industrial base and restore our prosperity -- will be a policy that will work elsewhere, too. This is why I am confident that conferences like this one can be very important in helping to build not just a local, but a national consensus about our energy future.

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THE ENERGY FUTURE: A NATIONAL AND STATE LEVEL PERSPECTIVE

1. The Changing Role of Government in Energy Policy

Jan W. Mares
Acting Under Secretary
U.S. Department of Energy

On behalf of the U.S. Department of Energy I am pleased to join in welcoming you to this conference. Tenth anniversaries always seem to represent special milestones. And in this case, Dr Hartnett and his colleagues should take an extra measure of pride in the fact that this conference now has a decade of tradition as an outstanding forum for public discussion. I am proud to be one of the participants addressing the conference.

It's been popular in many conferences like this -- particularly at 5 or 10 year intervals -- to look back over recent history and talk in terms of the "transitions" that have taken place -- transitions in fuel sources, in government policies, or perhaps in the geopolitical shifts in energy supply. There are, indeed, valuable lessons to be learned from such retrospective views.

I want to spend a few moments describing another energy transition, one that is taking place right now in this country and one that will play a dominant role in shaping the energy future of this state and that of the nation. The transition is in the public perception of energy and energy technologies.

This conference deals with coal and nuclear power. There is a common denominator that links both of these energy resources. To achieve their maximum acceptance into our energy economy, the public's perception of their risks and benefits will be as important as any government policy we create in Washington or Springfield. We've learned long ago that public acceptance cannot be guaranteed by government regulation.

Under the free market philosophy of this Administration, the American people are being offered an increased role and responsibility in determining our future energy mix. Yet, charting the correct energy path for this country will require a maximum of personal understanding and a realistic assessment of our energy situation.

The turbulent energy events of the 1970s helped create a crisis mentality among many Americans -- a tendency to turn long-term problems into overnight emergencies. In the 1970s, energy was thought of more as a cause than a commodity, a political issue,

sometimes pitting region against region, rather than a national challenge.

All too often, the mentality developed that the federal government was the only solution. More federal dollars would mean more technological breakthroughs and more energy production. More regulations would force wiser fuel use and more conservation. Larger government would mean more action and better solutions.

Today, however, there is a change taking place in our energy mentality. A recognition has evolved that there are no instant, magical answers, no secret formulas that will end our dependence on foreign oil overnight or even in the next decade or two. We have an abundance of energy resources in our country, but overnight solutions are simply not realistic.

Perhaps most importantly, the recognition has evolved that government alone does not hold the key to our energy security. Government has a role but that role must not impinge upon individual energy choices.

These are important changes in our perception. The country, as it moves into the 1980s, is adopting a more realistic outlook on energy -- one that recognizes that our strength lies in free and open market competition.

There is another aspect of the transition taking place in our energy mentality. We're beginning to see the emergence of a new generation of energy technologies -- more efficient, more economical, and more environmentally acceptable than the energy systems of the past.

In the coal area particularly, there is a growing perception that we no longer have to remain tied to 30- and 40-year old technologies. In much of the public's eye, coal has been thought of as the energy resource of last resort, one whose use was inextricably tied to increased pollution and scarred landscapes. But in the past few years, a group of modern, new coal technologies has emerged from our research laboratories -- some with government sponsorship, others privately financed. Together, this new generation of advanced technologies is changing our perception of coal.

Fluidized bed combustion is one example. This technology has now secured a foothold in the industrial boiler market and is making significant progress in the utility sector. We consider it one of our success stories. Government helped prove its technical viability in first-of-a kind units such as the one at the Great Lakes Naval Training Center. Industry then picked up the initiative and is now

moving the technology into more widespread commercial use. Today, nearly every boiler manufacturer either offers an industrial-scale fluidized bed unit or is involved in its own development effort.

The dry scrubber, a new generation of flue-gas clean-up systems, is another example of an emerging coal technology we believe could have a substantial impact on the eastern high-sulfur coal market. A commercial unit has been operating since spring 1982 at Argonne National Laboratory; we have found that burning Illinois-basin coal with the new scrubber compares favorably with the cost of low-sulfur coal from the West. Moreover, it will save the Department and the taxpayers more than a million dollars a year in fuel costs compared to burning oil or natural gas. It also will eliminate the disposal problems of the wet sludge common to most of today's scrubbers.

For the longer term, we are working with several industrial groups to develop substantially improved coal beneficiation techniques. Many are still in the early development phase; nonetheless, the laboratory tests sponsored by D.O.E. over the past year have increased our optimism considerably. Removal of 90 percent sulfur and ash from high-sulfur coals still appears technically and economically feasible. That would give even the dirtiest of coals an environmental quality rivaling fuel oil. Combine that advantage with new techniques for grinding and slurrying coal with oil or water to form an oil substitute, and the result could be the opening of a major new opportunity for the eastern and Midwestern coal industry. It will take continued development, but the potential is there. The technical objectives appear to be within our reach.

On a larger scale, the prospect of manufacturing synthetic fuels from coal, in my opinion, is still a very real and viable option for this country. We've heard a lot recently about the death of the synfuels industry, and everyone can point to examples where plans have been scaled-down, deferred, or in some cases, abandoned. In a time of level oil prices and high interest rates, that's the nature of marketplace decision-making.

The country has shifted away from a headlong plunge to establish a national synfuels production capacity. But I believe, at the same time, we've sharpened our commitment to establish the technical capability to produce synthetic fuels when future economic conditions warrant.

By October, 1982 construction of the nation's first commercial-scale plant for producing pipeline quality gas from coal will pass the one-quarter

completion mark. Counting engineering and design, the Great Plains coal gasification project in North Dakota is now roughly 50 percent complete and moving on schedule toward full production in 1984. Just recently, the Pacific Lighting Company asked to join the four-member Great Plains consortium. This, in our view, is additional evidence that synfuels are still an important part of many corporate planning strategies.

One can see this evidence in other areas of the country. In Tennessee, Eastman Kodak is continuing its project to use coal gasification for producing feedstock gas for chemical manufacturing. In California, the Coolwater coal gasification project, which will generate electricity from gasified coal, is continuing.

In Illinois, the Wood-River coal gasification project continues to move forward. I understand the gasifier was recently installed and the project continues to move toward start-up next spring. The Synthetic Fuels Corporation is also continuing its evaluations of several proposed coal liquefaction and gasification projects, preparatory to providing financial assistance.

So unlike the starts-and-stops of the past, this time the country is putting into place the technical foundation for a viable synfuels industry. I'm convinced that synfuels still represent an important strategic energy option for this country. These first synfuel plants will send a signal to the world that we have an alternative if oil prices continue to rise. The threat alone may help moderate oil price increases in the future.

These first plants also will give the investment community the financial track record they can use as a basis for future decisions. Most importantly, substantial private sector involvement now means that if future economics dictate an expansion of a synfuels industry, we will not have to revert to a costly, government-steered crash program. We will have the technical know-how already in place in our private sector.

Our nation's energy mentality is indeed changing when it comes to new coal technology: however, perceptions and tendencies change slowly. An example is the current debate on acid rain. There is still a tendency to declare an emergency and point an accusing finger without the necessary scientific evidence.

Recently, the Senate Committee on Environment and Public Works voted 15-2 to mandate by 1995 an 8 million ton annual reduction in sulfur emitted from utilities and industries in 31 eastern states,

including Illinois. The target was the older coal-burning power plants in the East and Midwest. By requiring the reduction of sulfur emissions from these plants, the problem of acid rain in the Northeast and the damage to New England's lakes and streams would be reduced or eliminated, according to the proponents of the mandate.

It was an action based more in rhetoric than in scientific fact, and one that, if upheld in future sessions of Congress, would place a major financial burden on this country with no guarantee that it would solve the problem.

The price tag of mandating this level of sulfur reductions could approach $5 to $7 billion annually. This is about the amount required to install scrubbers or to pay the higher costs of lower-sulfur coal. That could translate into a rise in electricity rates of between 4 and 25 percent for the affected utilities.

How many of those who voted for this bill realize that almost every one of the older coal-fired plants they targeted for sulfur reductions are expected to be retired between the years 1995 and 2020 anyway? Their replacements will have to incorporate the best available environmental control technology to meet existing Clean Air Act standards. As a result, our studies show that sulfur emissions would decrease by roughly the same amount, with or without the proposed new legislation.

The Wall Street Journal called the proposed bill another example of the "spend-first-and-ask-questions-later" approach to national policy. The Reagan Administration has proposed a more prudent approach that is no less committed to clean air and a healthy environment, but an approach that recognizes the need to base actions on solid scientific evidence.

There is a need to know, for example, if Midwestern coal plants are the only or even the main cause of the acid rain phenomena. Consider that sulfur levels in the Northeast have risen only 5 to 10 percent during the past 20 years, even though the tons of coal burned by utilities have increased almost 250 percent.

Also, consider that the combustion of oil, especially residual oil, has been found to produce significantly higher quantities of sulfates per unit of sulfur in the fuel as compared to coal. Sulfur dioxide, the principal form of sulfur released from coal combustion, must react with oxygen in the atmosphere before it can occur as acidic precipitation, while sulfates are already acidic.

Also consider that metal catalysts such as manganese, vanadium, nickel, and graphitic carbon are contained in more significant quantities in oil than in coal. We still do not know the role these catalysts are playing in the sulfate level around local oil-fired plants in the Northeast.

Consider that acid rain has been observed in Florida and California, two states in which there is little coal consumption and where the prevailing winds are from offshore.

We still do not know how to interpret scientific evidence that suggests soil composition, changing farming practices, the types of forests, and the make-up of the lake bottom may play a role in the acidity level of a lake. The point is that before we revert to the tendencies of the past and to overreact, we need to ask critical questions and obtain scientifically credible answers.

We need to take the same approach in nuclear energy. Public acceptance will depend on how credible our answers are to questions about reactor safety, radiation, waste management and economics. We need to restore the public's confidence that its health and safety will be assured through all stages of the nuclear fuel cycle -- from fuel fabrication to power generation to waste disposal and reprocessing.

If we put aside emotional rhetoric and look at the record and the technological progress made in the past years, we will recognize that nuclear power can and should play an increasingly important role in the nation's energy future.

Still, there are nuclear issues which need to be addressed squarely. We need, once and for all, to remove the lack of a final waste repository as a symbol in the public's eye of our inability to safely generate and manage nuclear power.

Disposal of radioactive waste is not a technical problem. In this area, we have asked the hard scientific questions for the last three decades, and we have scientifically credible answers. We know that disposal can be done safely and effectively. Now, it is time for action. Passage of nuclear waste legislation is one such action that will strengthen the resolve of this country to move the nuclear industry forward again. Nuclear waste is a bipartisan matter. The settlement of this issue is in the interest of all Americans.

We continue to support the development of the Clinch River Breeder Reactor. It is a necessary step if we are to maintain our technological lead when countries begin to choose new energy technologies. Seventy-five percent of the commercial light water

reactors in the free world are American built or licensed. If we are to maintain that standard of excellence and leadership as countries evaluate and adopt the breeder option in the future, we must move forward with construction of Clinch River.

This Administration has been accused of not having an adequate vision of our energy future. Unfortunately, many people mistake a predetermined blueprint for vision. Ours is not a predetermined blueprint. Instead, it will be determined by an evaluation and use of energy by the bill-paying consumer.

In those terms, coal and nuclear powerplants are going to have a distinct commercial advantage. A recent analysis issued by the U.S. Department of Energy showed that new coal-fired or nuclear plants will produce power at one-half to one-third the cost of operating existing oil- or gas-fired units.

The prospects for both new coal and nuclear generated power will depend upon the recovery of our nation's economy and the effect that will have on future electric demand. This Administration has linked its energy policy closely with its economic goals. We have made hard choices to reduce federal funds for some worthwhile energy projects in an attempt to reduce excessive spending which is the principal obstacle to economic recovery. The success of our Economic Recovery Program will do more to stimulate the energy industry of this state and of the nation as a whole that any other action we can take.

We've experienced good fortune recently in energy. We have learned the value of energy, and with that has come an increased awareness of the importance of energy conservation. We now use energy more efficiently than ever before. Our success in breaking the lockstep relationship between G.N.P. and energy consumption, the improvements in domestic energy production, and our progress in moving new technologies toward the commercial threshold -- all these are giving Americans a new, brighter perception of our energy future.

But we must be cautious not to let optimism be transformed into complacency. If there is to be one dominant transition in the energy mentality of this country, it is that we are no longer forced to jump from one crisis to the next. We are not energy secure yet, but we have the time to proceed along a pathway clearly defined by scientific understanding, economic realities, and social choices.

There is still a sense of urgency in our national energy policy -- but it is now urgency with

more clearly defined roles for government and industry. Our energy policy is based on distinct, but complementary roles for government and industry. In the federal research programs, for example, we have removed much of the overlap and duplication with industry that, in effect, was more of a detriment to progress than it was a help.

Government clearly has a role. It can provide assistance for work that is too long-range or too high-risk to attract industry support. It can support generic research -- in health and environmental matters that have applications across the energy spectrum. Concentrating federal dollars on these aspects of technology, rather than on commercial development, removes government as a competitor to the private sector. It allows industry to do what it does best -- assess risks and select those opportunities that make the most commercial sense.

We are improving our national energy situation. We are making progress toward the day when energy ceases to be a national problem and again becomes a symbol of our national strength.

2. The Unpredictability of the Energy Future

S. David Freeman
Managing Director
Tennessee Valley Authority

It is appropriate that we begin by looking at the record of the past nine years. The years since the energy world was turned upside down by the Arab oil embargo of 1973.

This nation's foremost energy accomplishment of this period has not been achieving increased production. Despite a ten-fold increase in the price of crude oil, U.S. production in 1981 was about the same as in 1973. Natural gas production was down. Production of coal and uranium has gone up some, but overall, neither consumption nor domestic production of energy has increased in the last nine years.

Our outstanding energy achievement since 1973 has been in the area of energy conservation, not energy production. We have demonstrated that conservation can be a major source of energy to fuel economic growth. The evidence also clearly indicates that the conservation opportunities are very large. We have hardly begun taking the actions necessary to achieve a truly energy efficient economy.

Perhaps the most significant indicator of what has been achieved is the declining ratio of energy consumption to economic output. In 1973, we were consuming 59 units of energy for each unit of gross national product in our economy. In constant-dollar terms, the ratio had been reduced to 49 units of energy per unit of GNP by 1981. The 17 percent real increase in the GNP since 1973 has thus been fueled entirely by conservation.

This considerable advance suggests the fallacy of the long-accepted notion that there is some kind of iron link between increased energy usage and economic growth. What we discovered was that we could heat our homes and get to work with far less energy than we previously used, just to name two obvious examples. And we found that we could heat new homes and fuel new cars with the energy we saved. The economy therefore grew 17 percent from 1973 to 1980 while energy consumption remained constant.

This is not to say that the price of energy does not have an impact on economic growth. In the short term, skyrocketing energy prices can help to stop growth dead in its tracks, as we discovered in the embargo-induced recession of 1975, when the GNP sank

in real terms, and as we again discovered with the sinking real GNP of the current recession.

Nevertheless, the fundamental energy lesson of the past decade is clear. Given time to make the required adjustments in behavior and equipment, conservation can be a major option to allow economic growth.

Conservation can be compared directly with alternatives such as coal and nuclear in evaluating options for meeting future needs. And we now know that in most cases, conservation will emerge from this comparison as clearly superior on the basis of hard-nosed economic analysis. Conservation also helps to conserve nonrenewable resources; it can be developed much more quickly and flexibly than new power plants; and it is more reliable than central-station energy production.

Ten years ago, to most experts, the idea of influencing the demand side of the energy equation was simply foolish. Most everyone "knew" that economic growth was dependent on building enough new centralized power plants and drilling enough new wells to meet a demand for energy that was expected to continue growing at 3 percent annually. The consensus then was that total energy consumption would more than double by the year 2000. We were told that only by undertaking a massive power plant construction program and by drilling tens of thousands of new wells could we keep the country's economy growing.

This position did not go unchallenged. I am proud to have been among those who helped to lay the conceptual foundation for a different approach. The Ford Foundation Energy Policy Project, which I directed, pointed out in the spring of 1974 that substantial economic growth could be achieved with a much slower rate of growth in energy consumption. At the time, this was regarded as a radical point of view, and we were roundly criticized as advocates of zero economic growth. Subsequent events, however, have proved that economic growth can be maintained and perhaps even enhanced by more efficient use of energy. Much of the economic growth that has taken place over the last decade has been fueled by conserved energy.

Since 1977, I have been privileged to serve as a director of the nation's largest producer of electric power, which has implemented a very large and successful conservation program. At the Tennessee Valley Authority, we have put into practice much of the conceptual framework of energy demand management that we developed at the Ford Foundation in the early

1970s. TVA's institutional commitment to this concept is now reflected in the very structure of its Office of Power, which has been divided into two parts. One is devoted to electricity production and the other to energy use. We consider energy conservation as an option along with new power plants to supply enough electric power for a region that still looks forward to healthy economic growth.

Under TVA's Home Insulation Program, for instance, we have completed more than 500,000 home energy surveys and provided more than 250,000 interest-free loans for energy efficiency improvements. This represents a survey penetration rate of more than 20 percent, the highest of any large power producer in the country. By 1990, we expect to be saving the capacity equivalent of a large nuclear power generating unit through this program alone, at a fraction of the cost of building that unit.

The Home Insulation Program is only the most visible among a host of conservation and renewable energy efforts TVA has initiated in recent years. Commercial and industrial consumption accounts for about half of all TVA power use. TVA offers energy surveys and conservation loans at below-market rates to qualifying firms. The program is expected to cut peak demand on the TVA system by almost half of the output of a large power plant in 1990. And TVA is also demonstrating load-management techniques that will flatten the peaks in our future load curve. In the renewable energy area, TVA offers a comprehensive program promoting the use of solar water heaters, wood heaters, and passive solar design in homes and businesses as well as in TVA facilities.

At TVA, the combined impact of conservation and renewables, rising prices and the changing pattern of growth has already been dramatic. It has radically altered our outlook for growth in demand for electricity. Whereas our power people were expecting a demand growth rate for electricity of 7 percent as recently as the mid-1970s, our forecast today is for growth in the range of 0.7 percent to 2.5 percent through the year 2000.

This lower demand forecast has required substantial adjustments in TVA's power plant construction program, including the deferral of four units and the cancellation of four others. Replacing these power plants with conservation will result in rates some 10 to 20 percent lower than they would otherwise have been in the 1990s.

The record thus reveals that energy conservation, not production, has been America's primary counter-punch to the OPEC oil weapon. But the record

also reveals that our conservation efforts has been only partially successful and that energy usage is down in large part because our economy is down. We have only begun to conserve. We should not deceive ourselves into thinking that we have done more than we actually have.

Many people now believe that America has won the energy war with OPEC. The energy crisis is over, they say, and we can now simply go back to business as usual. We comfort ourselves with the thought that the gas lines have disappeared temporarily. We talk reassuringly of an oil glut amid predictions that world prices will remain stable through the mid-1980s.

But in so doing, we ignore the obvious: We are still importing close to 5 million barrels per day of foreign oil, almost as much as the 6 million we were importing at the time of the devastating Arab oil embargo. In fact we are importing more oil from the Arab members of OPEC, than at the time of the embargo. Oil imports are draining $50 billion a year from our economy, endangering our national security through our dependence on the volatile Middle East, and contributing to the world-wide recession by inflating the price of oil.

As I indicated, one of the principal reasons why oil imports have declined from their all-time highs of the late 1970s is that we are in a deep and prolonged economic recession. While conservation has also played an important role--and can play an even more important role in the future--much of the nation's energy-intensive industrial plant is simply lying idle at the moment. In the Tennessee Valley, large industrial users are operating at only 58 percent capacity.

Nationwide, we are facing a genuine depression in the energy-intensive sector of our economy, and if we ever emerge from it, energy usage--and oil imports in particular--are going to skyrocket. The current low level of industrial operations represents a drastic curtailment of energy consumption as a result of economic conditions rather than the completion of the task of increasing our energy efficiency as a nation.

There is an old expression that the more things change the more they stay the same. My last appearance at this conference was back in 1975 in the middle of our last recession. As I observed then:

> We have unemployment and we have a slowing down of the GNP, and it did not come from conservation. The problem rather is that

> our high energy civilization is running short of energy at a price people can afford to pay.

Twice in less than a decade, we have been faced with dramatic increases in energy prices, followed by major economic slowdowns. It is no accident that the quadrupling of oil prices in 1973-74 was followed by the recession of 1975. And it's also no accident that the redoubling of oil prices in 1979 triggered the current world-wide recession. Let us not forget that despite all the talk of oil price stability, crude oil has jumped from $3 a barrel in 1973 to $30 in 1982.

The economies of the high-energy nations are depressed in large part because they have not yet developed a growth pattern that minimizes the enormous drain of paying their energy bills. As I said in 1975, "We are in for slower economic growth until we put together a growth pattern for this country that is consistent with a less energy-intensive economy and a more knowledge-intensive economy."

The value of conservation can be seen most clearly when it is viewed as a way of increasing the nation's productivity. We, of course, need to continue to increase the use of coal and nuclear somewhat in the near future, but to increase productivity we must try to develop more of the conservation potential and less of the much more expensive production alternatives.

The cost of coal and nuclear plants must also include the cost of overcoming the serious environmental and safety hazards they pose. And I'm not sure we can adequately control them at a price we can afford. The impacts of sulfur dioxide are well established. The scientific evidence continues to tie acid rain to burning coal and the build-up of CO from merely burning fossil fuels could create a "greenhouse effect" that poses a threat to the entire planet. And the Three Mile Island accident demonstrated that today's light-water reactors are part of a technology that is capable of self-destructing.

The nation's support for clean air and nuclear safety continues unabated despite the change in administrations. Ensuring that these values are maintained is greatly inflating the price of central station generation. Conservation presents the possibility of achieving hundreds of billions of dollars worth of savings to the economy in comparison with building new power plants or importing more oil. I'm certainly not saying that coal and nuclear power can not play a major role in providing an energy

"bridge" into the next century. But conservation constitutes a much quicker and more cost-effective way of carrying a larger share of the land.

That brings me to the crux of my argument here today. If we are to attack our continued energy dependence with the seriousness it deserves, we must mount a truly comprehensive conservation strategy. That will mean making the investments in energy research and development and in retooling our industrial bases that are required to put our energy system and our economy on a sound and sustainable footing. It will take billions of dollars--and I realize that dollars by the billions are considered to be in short supply in the national budget today. But unless we make these investments in a more efficient energy system based on renewable energy and a less energy-intensive pattern of growth, we will spend even more billions--and send most of it overseas. We will continue to exhaust our strength and our resources in the effort to drain this nation and the world of oil and gas and to exploit coal and nuclear in unwise ways.

What sort of investment program am I referring to when I speak of the need to make the commitment to a more sustainable economy? We need to concentrate our efforts on research and development in those areas that will contribute to a truly balanced energy system. We particularly need to spend money to find ways of improving our energy efficiency, including improved home weatherization and construction techniques, more efficient industrial drives and development of the 75-mile-per-gallon car.

Recently, the CBS evening news featured a piece on a prototype of an automobile that can get 100 miles to the gallon. Unfortunately, Detroit is not prepared to retool to produce this vehicle because it does not have the capital. We have not made it a national priority, even though military experts would agree that spending a few billion dollars to put this vehicle on the road could do far more for the national security than equivalent spending on new weapon systems.

We also need to make a major push for further research in renewable energy areas like biomass, wind, photovoltaics, passive solar design and the like. And we need to find more reliable ways of utilizing nuclear power and cleaner ways of burning coal, both of which can help to form an important bridge to the sustainable society.

The energy future remains uncertain in its details. No one knows exactly what the price of oil and gas will be next year, much less a decade from

now. But it is time to face the cold hard fact that economic growth fueled by cheap energy has run its course. The U.S. has entered an era in which economic growth will be dependent on developing a much less energy intensive pattern.

This is already beginning to take place. The computer-based information service sector is doing fine. The heavy manufacturing sector, which is dependent on lots of energy and raw materials, is doing poorly. The importance of energy in the future lies in the impetus it will give to the entire economy to become leaner and more efficient. Every power plant we don't build represents money the consumer can spend for services and high-technology goods.

It is time to recognize that the really important unit of production in America's economy from now on will be the human brain and not heavy machinery fueled by expensive oil and gas and electricity from large power plants. We have a tremendous potential for using knowledge in this computer age and for providing services and high-technology products to a population that will live longer and be better educated.

As a nation, we have been overspending and underinvesting in developing our true potential. We need to make it a matter of national policy to encourage a major shift in capital away from production in forms that are no longer economic. We need to emphasize investment in developing the skills of our people and in producing new goods that are suited to the post-industrial age.

Our economy has been badly depressed in the last decade as a result of escalating energy prices. The lesson for the 1980s is to move rapidly to end our petroleum dependency in the most cost effective and efficient way. That means a growth pattern that uses far less of what has now become a very scarce and expensive item. I know it is difficult for people who spent their lives believing that energy was the steam engine of economic growth to believe that less is more, but that's the name of the game for the 1980s and 1990s.

3. Governmental Regulation of Coal and Nuclear Power Plants

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Electric utilities have experienced considerable difficulty in recent years bringing on new capacity, particularly nuclear plants. An intense public debate has revolved around the safety of nuclear plants, acid rain and other actual or potential environmental damages from coal production -- even the need for new capacity in the face of much lower rates of electric growth. Unfortunately, much of the debate is ideological, with insufficient attention given to other underlying trends in fuel prices and economic conditions that dramatically affect the utilities fuel mix and without sufficient realization that all energy options create environmental hazards. I hope to put some of these issues in perspective, particularly to focus on the differing impacts of health, safety and environmental regulation as compared to economic regulation. But first, I would like to explore some of the root causes of the utility industry's financial distress and how they relate to other regulatory issues.

Before 1970, the electric utility business was a pleasant one with which to be associated. Electric rates generally fell through the 1960's as larger and more efficent generating and transmission units lowered costs and regulatory lag. These tranquil times allowed for the creation of a dependable and financially secure electric utility industry.

Considering the current position of the utility industry, only a bit over a decade from its halcyon days, it is worthwhile to ponder what happened. The industry's problems began at the end of the 1960's, when real electricity prices began to increase -- by 1971 faster even than inflation. Nevertheless, by 1973, the utility industry was not in particularly bad shape and the ratio of its market value to book value was greater than one. It wasn't until after the Arab oil embargo that electric utilities encountered truly serious financial problems and unfavorable performance measures. This was repeated at the time of the second oil price shock in 1979-80.

In 1974, the year when the full brunt of the Arab oil embargo was felt on the economy, the consumer price index shot up 11 percent. The electri-

city component shot up even more -- by 18 percent -- and again outpaced the CPI in 1975. These price increases led to consumer resistance and hence to a reluctance by state public utility commissions to grant adequate rate increases.

By 1974, the industry was in trouble. A record number of credit rating downgradings occurred, a greater percentage of earnings came out of allowance for funds used during construction, and average market to book ratios fell by .77.

Why would the industry experience such widespread damage considering that generation from oil constituted only 15 percent of total U.S. electricity output? First, the oil price shock caused rapid inflation and higher interest rates, both of which hurt the utility industry with the largest capital program of any industry. Second, it cut demand increases in half, reducing revenues available to utilities. Third, it made a large coal price increase possible, which resulted in higher fuel costs for another 50 percent of the total. Finally, because of a lengthening of the regulatory process and the oil price shock inflation, nuclear plants became increasingly more expensive.

The three years, 1976 to 1978, were years of recovery as coverages, market to book ratios and other measures improved. During these same three years, real world oil prices declined.

Then came the second oil shock with similar devastation. The market to book ratio fell from .86 in 1978 to .79 in 1979 and continued to fall in 1980. More credit downgradings occurred, non-cash profits began to dominate total profits, pre-tax interest coverage continued to fall -- from as high as 4.9 times in 1967 to 2.8 times in 1979.

Today, most utilities are somewhat better off than they were in 1980. Just as after the Arab oil embargo, utility stock values have risen, buoyed by the general bull market during the summer of 1982. Oil costs, inflation and interest rates have been falling -- all good signs. But the future is not without peril. Embedded debt costs will increase capital costs for the industry as a whole, shrinking further pre-tax interest coverage. Solomon Brothers analysts estimate that over the next three years, six billion dollars of long and intermediate term debt will need to be refinanced, with an average interest cost of 7 percent. The extra debt costs could lower the pre-tax interest coverage without an improvement in earnings.

There are other storm clouds on the horizon. Some public utility commissions have been reluctant

to approve rate increases. Many states are considering moving from appointed to elected commissions because of a public concern that appointed commissioners have been too easy on utilities. Both Michigan and Ohio have referenda on the ballot to switch. Efforts to put similar referenda on the ballot failed in Colorado and Oregon because of insufficient signatures and in Arkansas because of legal challenges.

At best, one can conclude that the regulatory environment is uncertain. Utilities may be able to nurse themselves back to health before another oil price shock. While certainly a more hopeful prognosis than a year ago, it is not really good enough for the nation's most capital-intensive industry.

The effect of government environmental and nuclear regulation must be viewed in the context of a financially weak electric utility industry, a low rate of demand growth and high interest rates. Under these conditions, regulatory requirements that add to capital costs can contribute to the financial demise of coal and nuclear projects, although under more auspicious demand and economic conditions, the projects would not be threatened. State public utility commission rate regulation clearly has played the most critical role in determining the financial viability of utilities and hence reducing the financial feasibility of nuclear projects. If public utility commissions had been more accommodating, nuclear energy would be playing a larger current and potential role in providing electricity, while coal and oil would provide a somewhat smaller contribution.

Regulation of nuclear power plants has affected costs in two ways. First, the protracted licensing process can cause extensive delays in bringing plants on line. Second, continued upgrading of safety standards increased costs. Coupled with inflation and high interest costs, some new plants are costing more than $3 billion, many times more than initial estimates.

Reforming the nuclear regulatory process would be desirable. But whether it will be politically or practically possible to reduce the licensing period substantially is open to question. At best, a few years might be shaved from the total 14 years or so required to bring a nuclear plant on line, still leaving nuclear projects extremely vulnerable to shifts in demand, inflation and interest rates.

If anything, future costs for nuclear facilities are likely to be higher. As more experience is gained, even more flaws will be found in nuclear

plants, requiring modification on new and existing plants. Current nuclear plants have much more expensive safety features than earlier ones, and this trend is likely to continue for the indefinite future. Recently, the Nuclear Regulatory Commission, in a study of nuclear plants, pinpointed 40 units that may eventually need to make modifications to guard against thermal shock, a potentially dangerous rupture of reactor walls made brittle from long exposure to radiation. Annual repair bills are increasing as plants age. For example, Carolina Power and Light estimates almost a doubling of annual repair costs from 1981 to 1982.

The most pressing issue facing the nuclear industry is not the lack of new orders, but rather the cancellation of plants currently under various stages of construction and licensing. Some observers have estimated that up to half of these facilities in the pipeline ultimately would not be built. For some of them, low demand growth and higher costs have simply eroded their economics. In other cases, however, plants have been cancelled because utilities simply did not have the financial strength to finish them. In cases where nuclear plants would have backed out foreign oil, the facility may well have been economic although not financially viable.

This latter point deserves some explanation. Comparing the net present value of operating a nuclear facility with a baseload oil plant, it is highly likely that the nuclear plant will be cheaper. One would accordingly expect consumers to benefit when the nuclear plants go into the rate base. But under traditional utility rate-making, assuming denial or only partial use of CWIP, the revenues required in early years are extremely high, dropping as the plant is depreciated. The practical effect is to raise rates for a cost-saving measure, which will not be easy to explain to ratepayers. Hence, public utility commissions have a strong incentive to discourage construction of large new capital facilities.

Nuclear's problems are tied to four regulatory constraints: the protracted licensing process, the safety standards, the restraints on utilities' returns and an accounting system that is biased against large capital projects. The licensing process could be speeded-up a little but safety standards are likely to become even more rigorous. Utilities are becoming a little healthier, but mainly because their construction programs are limited, and a change in the financial accounting systems would be

revolutionary to both state regulatory commissions and Wall Street.

The nuclear industry faces other challenges. No national policy currently exists on either waste management or away from reactor storage, despite the almost two decade history of the civilian reactor program. Reprocessing and other issues are still unresolved. Considering this backlog of problems and the unstable financial position of utilities, it seems unlikely that new orders are in the offing for some time. The real issue is how many of the plants currently in the pipeline will ever be built.

The Clean Air Act creates the most extensive environmental requirement faced by the utility industry. A Congressional Budget Office study estimates that between 1980 and 2000, $33 billion would be spent on air pollution control capital facilities, about 20 percent of total capital requirements for coal-fired plants. Pollution control costs accounted for 4.4 percent of the average ratepayers bill in 1980 and these capital investments would increase these costs to 6 percent by the year 2000. While these pollution control costs are not insignificant, and must be added to environmental costs associated with extraction and disposal, they have not risen nearly as much as the costs associated with competing fuels. Real oil prices have increased five-fold since 1972 and natural gas prices are rising quickly as a result of the formula established under the Natural Gas Policy Act. Nuclear costs have gone up for the reasons described. For baseload generating plants, coal has a commanding current or prospective edge over oil and natural gas and competes quite favorably with nuclear energy.

Another regulatory concern that is often mentioned is the lengthening of time needed to bring a new powerplant on line. From 1970 to 1980, the average construction time for a coal-fired plant increased from 4 to 7 years. Although these delays are usually attributed to regulatory requirements, the CBO study found that the average PSD permit for a powerplant took just under a year. Probably the true story is that a number of factors are involved, including delays in equipment delivery and labor difficulties. At any rate, the change in construction time is obviously of profound significance of utility planning and certainly does increase the potential financial risk of new capital commitments.

The Clean Air Act does not substantially discourage construction of new coal-fired facilities, but it might have two modest impacts on coal use.

First, on the margin, the extra costs might discourage some investments in coal facilities, whose major purpose is to phase out oil use. Second, requirements to meet ambient air quality standards could inhibit conversion of some marginal coal-capable plants from oil to coal.

Coal conversion is an extremely important issue for some utilities and regions of the country. While the Clean Air Act has played a role in a number of conversion decisions, it is unclear whether it has been the decisive factor. For some utilities, local concerns over aesthetics and noise act as a barrier. But by far the biggest issue facing utilities has been the problem of quick cost recovery of coal conversion investments. With their weakened financial condition, utilities have a difficult time financing coal conversions that do not have an extremely fast pay-off, unless, of course, they have recourse to construction work in progress (CWIP).

Massachusetts faced up to this problem by allowing utilities to recoup two-thirds of the savings from a coal conversion project -- the difference between the costs of using coal and oil -- until the capital costs were paid off. The ratepayers immediately would receive one-third of the benefits and eventually would receive the other two-thirds. A Massachusetts Task Force, which I am chairing, is currently reviewing whether some guarantee of the spread between oil and coal prices would be necessary for some of the more expensive conversions, particularly those undertaken within Boston.

The Massachusetts law has already stimulated one coal conversion and should encourage many others. (New England Electric System earlier switched its Brayton Point facility to coal through use of CWIP; since this facility was essentially regulated by the Federal Government, CWIP was allowed.) Florida and Georgia have both developed systems similar to that used in Massachusetts. The point is simply that overcoming financial obstacles to coal conversion is much more important than worrying about hypothetical environmental requirements. Once financial mechanisms are in place, it is then possible to face up to the costs and problems with meeting these requirements. In fact, in Massachusetts, the coal conversions to date have received delayed compliance orders, allowing utilities to use cheaper coal while they were making the capital investment in environmental controls.

In conclusion, I would rate public utility regulation as having the biggest effect on new

construction of either coal or nuclear plants. Many utilities have strong incentives to avoid capital expenditures for new baseload plants, pursuing instead a combination of conservation, alternative energy projects, continuation of existing facilities beyond their normal life and a certain amount of prayer. Licensing and regulation of nuclear power plants has raised costs considerably, but inflation, high interest rates, lower demand and an unfavorable economic regulatory environment has been much more damaging. The Clean Air Act has had the least impact, as evidenced by the brisk rise in utility coal use since its inception in 1970, at the expense, I might add, of nuclear power.

There are some public policy steps that could be taken to encourage construction of a greater number of nuclear and coal plants where they make sense, generally in areas now heavily dependent on oil, and in the future, dependent on natural gas.

- Continuation of the current public utility commission trend of increasing real rates of return for utilities. For many utilities, restoration of their financial integrity is a sine qua non for commencing a new construction program.
- Use of mechanisms similar to that used in the state of Massachusetts, Florida and Georgia for financing oil conversions.
- Streamline the nuclear licensing process.
- Experiment with rate structures that avoid front-loaded financing. Various forms of levelized or even inflation-adjusted amortization schedules should be reviewed to overcome financial barriers to the construction of new capacity.
- Deregulate by expanding PURPA.

I would not wish to imply that all economic regulation has created bad results. Many utilities have been forced to review alternatives to construction, often discovering that cheaper options were available. Whatever heuristic value might have been attained, however, the current regulatory environment is clearly impeding a least-cost solution. While utilities should explore all their options in meeting potential future demand growth, it is senseless to rule out construction of new capacity as an unimportant element in a least-cost strategy. We have learned that what we need from energy policy is not governmental prescription, but rather an opening of the range of alternatives. That is the point to which regulators should address themselves.

4. Illinois' State Energy Planning

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As background information, a brief history of formal energy planning in the Illinois Department of Energy and Natural Resources (ENR) is in order. In late 1979, Illinois Governor James R. Thompson signed the Energy Policy and Planning Act. About two years after that ENR received initial funding for energy planning through the state appropriations process. The Energy Policy and Planning Act of 1979 was an expression of state policy as well as a guideline to be used in the planning process. As could be expected, the Act states that it is state policy to increase the utilization of our indigenous renewable and conventional energy resources, to emphasize state and local solutions to our energy problems, and to encourage, wherever possible, private contributions to the solution of energy problems.

At the same time, the Act sets forth the following guidelines to be used in our planning efforts. Among them are:

- Energy problems being faced in the State can be effectively addressed only by a government that accepts responsibility for dealing with them comprehensively, and by an informed public that understands the seriousness of the problem and is ready to make the necessary commitment.
- Economic growth, employment, and production must be maintained.
- Policies for the protection of the environment must be maintained.
- Solutions sought as part of the master planning process must be equitable and fair to all regions, sectors and income groups.
- Growth of energy demand must be prudently restrained through conservation and improved efficency of energy usage.
- Energy prices should generally reflect the true replacement cost of energy.
- Energy producers and consumers are entitled to reasonable certainty as to governmental energy policy.
- Resources in plentiful supply must be used more widely, and the State or locality must begin the process of moderating the use of those resources in short supply.

Given the statutory charge, ENR decided after a few inevitable false starts that the most valuable contribution the Department could make would be to prepare a series of documents describing, as best we could, Illinois' energy system as it now exists, how it has changed in recent years, and what can be reasonably expected interms of supply, price, and energy service demand in the near and mid-term. Our foremost, self-imposed, requirement was that these documents must allow any interested and determined reader, not just energy experts, to understand and interpret major energy issues facing the State. This requirement was based on our conviction that an informed public debate is probably the best catalyst of intelligent energy policy. Energy planners, after all, do not establish energy policy--this must be done in the General Assembly and by the Governor.

Finally, the Department had to face the question of where to begin and what the overall theme of our planning effort should be. The following factors affected our planning:

- We were not starting with a clean slate. Since 1977 Illinois has had aggressive energy conservation programs. Development of Illinois' coal resources, renewable resources, and nuclear safety programs were then, and still remain, a high priority of Governor Thompson and the General Assembly. The success of these programs has allowed us to take a slightly longer and broader view of Illinois' energy problems than if the state were starting from scratch. It also forced us to adopt a healthy view of planning--that planning is one on-going element of a state's broader energy program.
- Economic development and revitalization will continue to be the most important public policy issues in Illinois in the immediate future. Any descriptive planning effort must place energy in the context of our broader economic system, and that the theme of our work must be the energy-economic link.

In our planning then, we have sought to describe the effects that our current and past energy situation has exerted on Illinois' economy, and what role energy initiatives could play in the State's economic future.

The results of our work are presented in a series of six volumes. The first five volumes are off the presses and are now being distributed widely. In addition, ENR published numerous technical reports and staff working papers in support of the planning process -- these have also been circulated, but will

not become a formal part of our Energy Plan publication series.

Volume Six, "Energy Efficiency and the Illinois Economy: 1980-2000," is undergoing revision and will be out by the end of 1982. That volume will attempt to synthesize the information presented in the proceeding volumes. It also will represent an attempt at representing options for responding to the energy-related factors that continue to shape the economic future. It does not represent the end of the planning process. It is in this sixth volume that you will find further descriptions of the energy-economy link and two possible energy futures for Illinois.

Let's examine the energy-economy link in Illinois, how it differs from the energy-economy link in other states, and how this link has changed over time. During the period 1972 to 1979, three shifts were occurring which have deeply affected the rela tionship of energy to the Illinois economy. First, Illinois shifted gradually to the use of energy resources imported from outside the state. Second, there was a drastic run-up in the price paid for energy supplies. And third, Illinois experienced a steady growth in energy demand. Any of these factors acting individually can effect an economy. Acting together, their effect can be quite signi ficant.

Rising Energy Prices and the Illinois Economy 1972-1979

In 1972, prior to the OPEC price shocks and dramatic increases in electricity and natural gas prices, Illinois paid approximately 2.9 billion dollars for energy imported from domestic and foreign producers. (This figure is based on prices at first point of sale in Illinois, and therefore, does not reflect the prices actually paid by final consumers.) As shown in Figure 1, about 40 percent of this amount went to domestic energy producers in such states as Texas, Louisiana, Oklahoma, Montana and Kansas. In addition, foreign oil producers received 10.7 percent or slightly over 300 million dollars of this total. The remainder, approximately 1.4 billion dollars, eventually found its way back into the Illinois economy in the form of payments to holders of energy company stock, and producers of energy-related equipment, and as federal government expenditures funded in part by taxes on incomes and profits in energy producing states. In addition, receipts from

Distribution of Income from Energy Imports in 1972 and 1979:
Dollar Drain to Other States and Foreign Producers

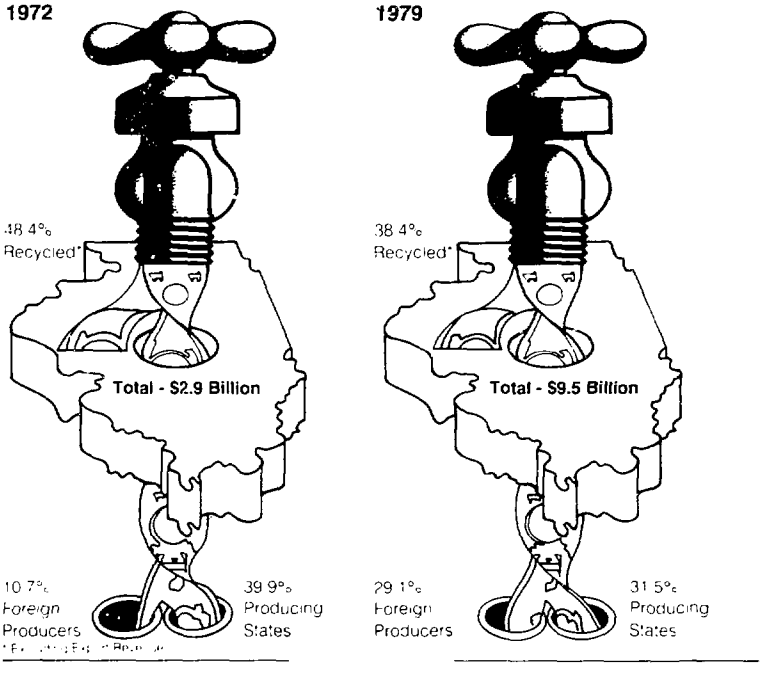


Figure 1

coal and oil exports equal to 362 million dollars helped to reduce Illinois' 1972 net energy import bill to 1.1 billion dollars. This bill was equal to roughly one percent of state personal income and 0.9 percent of gross state product.

The economic impact of energy price increases since 1972 is most easily seen, if for the purpose of the illustration, energy consumption is held constant between 1972 and 1979 (Figure 1), and we look only at the effect of rising prices on Illinois' energy import bill. During the period 1972-1979 the real price of gasoline increased by about 46 percent, natural gas by 50 percent and electricity by 17.7 percent. Consumers could only recognize the impact of increases in these end-user prices. However, it is important to understand that these increases were driven by even greater increases in prices at the

wellhead (in the case of petroleum and natural gas) and minemouth (in the case of coal.)

Several studies have shown that the income generated by increases in producer (wellhead or minemouth) prices goes mostly to the producer and the producing state or nation. Taking into account the source and magnitude of energy price increases between 1972 and 1979, and assuming that nothing in Illinois' pattern or amount of energy consumption changes, the state's fuel import bill was still approximately 4.5 billion dollars greater in 1979 than it was in 1972. Stated another way, had Illinois been able to hold its consumption of imported fuels in 1979 equal to what it had been in 1972, they still would have paid over four billion dollars more for energy.

Of this additional 4.5 billion dollars paid out for price increases in energy imports between 1972 and 1979, approximately 60 percent ($2.85 billion) went directly to energy producers and producing states and nations. After subtracting the approximately 363 million dollars brought into the state's economy from increased prices for coal and oil exports, Illinois was left with a net loss of 2.5 billion dollars greater in 1979 than 1972 due solely to energy price increases. This drain is equivalent to sending almost 220 dollars from every Illinois resident to energy producers, and represented about 1.75 percent of 1979 gross state product and two percent of state personal income.

Although the direct loss of income due to energy price increases is substantial, it still understates the negative impact of rising prices on the Illinois economy. The reason is the existence of what economists call the "multiplier effect." Stated another way, if Illinois could have somehow recaptured the 2.5 billion dollars lost in 1979 to energy producers as a result of rising energy prices and spent it locally, the state's economy would have been capable of employing approximately 240,000 more workers--considering both direct spending and the multiplier effect.

The Cost of Energy Imports - 1979

In reality, Illinois' gross energy import bill tripled between 1972 and 1979, rising from slightly under three billion dollars to about 9.5 billion dollars. As stated above, 4.5 billion dollars of the 1979 gross total is directly attributable to energy price increases. The rest, about five billion

dollars, can be traced to changes in Illinois' energy consumption patterns.

Between 1972 and 1979, a number of changes occurred in Illinois' fuel import pattern. These changes, combined with increasing consumption, account for the five billion dollar portion of the state's 1979 import bill not explained solely by energy price increases. Of greatest importance was the dramatic increase in the proportion of Illinois refinery crude oil inputs coming from foreign sources. In 1972, inputs of foreign oil to Illinois refineries accounted for only about 11 percent of total refinery inputs. By 1979, however, that share had increased to 49 percent. As the share of refinery inputs imported from abroad increased, the absolute amount of income, as well as the share of Illinois' import bill going to foreign producers increased. Second, total fuel consumption in Illinois increased by almost eight percent between 1972 and 1979. This increase, combined with rising prices, led to a major shift in the distribution of income for Illinois' fuel import bill.

In dollar terms adjusted for inflation, final estimates that include the combined effects of changes in price and consumption patterns indicate the following:

- Of Illinois' 1979 gross import bill of 9.5 billion dollars, 3.7 billion were eventually returned to this state's economy.
- Of the remaining 5.8 billion dollar import bill, 3 billion were paid to other states and 2.8 billion were paid to foreign oil producers.
- Even when this import bill is offset by Illinois' energy exports to the sum of 855 million in 1979, Illinois' net import bill stands at 5 billion dollars. In short, it has quadrupled since 1972.[1]

Again, the full impact of this income loss is significantly greater than the initial flow of energy dollars out of the state because of the multiplier effect. If for example, the five billion dollars lost to energy producers were added to the Illinois economy, the gross economic output would have been almost 12 billion dollars higher, and the economy could have supported 480,000 more jobs.

Frequently, this kind of analysis makes economists uneasy. This example is purely hypothetical in the sense that the five billion dollars lost to energy producers in 1979 for the most part could not have been totally prevented. But, it does illustrate

the point that the energy dollar drain can have significant adverse economic impacts.

Conclusion

Energy prices will continue to increase, (although perhaps at slower rates) for the foreseeable future, posing the threat of an increasing loss of state income, output and jobs. As the Illinois economy suffers, so will the ability of the state to provide services for citizens of Illinois.

Increased production and exports of Illinois' energy resources will help offset the dollar drain, although this alone is unlikely to have a significant impact in the near term. Rather, the protection of individual consumers, as well as the Illinois economy, from the impacts of rising energy prices requires a broad-based effort to reduce dependence on energy imported from other states and nations. This, in turn, requires aggressive efforts to improve energy efficiency, as well as to substitute Illinois' energy resources for imported oil, natural gas and coal where feasible. These efforts will be rewarded not only through a reduction in the flow of energy dollars out of the state, but through additional economic activity in Illinois as well as the stimulus provided by expenditures on locally produced energy services recirculating through the state's economy. With this in mind, let me review two scenarios for Illinois' energy future, "Business-as-Usual" and "EEF" or "Energy Efficient Future."

ENR's definition of business-as-usual has nothing to do with historic trends. It refers to the usual behavior of consumers in response to normal stimuli--in this case, energy prices. ENR's expectation is that consumers will use less energy, from now through the year 2000, than they would have used in the absence of the dramatic price increases of recent years--and the anticipated lesser price increases of coming years. If probabilities were assigned to the range of possible energy futures for Illinois, the following is one which ENR most expects.

The Business-As-Usual Path

During the next two decades, Illinois will experience modest population and economic growth, along with rising living standards. Businesses and individual consumers will require more energy ser-

vices in the aggregate. Current analysis projects average annual growth rates in energy consumption of about one-half of one percent in the business-as-usual scenario, compared with an average growth rate of 2.2 percent yearly in the 20 years from 1960 to 1980.

This projection is based on an expectation that commerce and industry will grow by 50 percent between 1979 and 2000, while crop production will increase by a third. The number of households is expected to increase by a quarter in the 20-year period. More travel is anticipated, along with more energy services for the home, particularly air conditioning.

But even the one-half of one percent growth rate in energy rate in energy consumption that is projected for the period will be costly for consumers, with Illinois paying perhaps twice as much for energy in the year 2000 as it did in 1979. This increase in total energy costs would come despite price-induced energy conservation.

Now assume those same growth rates in Illinois economic activities, business and industry, agriculture, housing, travel, etc. and see if it is possible to influence growth rates in energy consumption and the total costs for energy in Illinois from 1979 through the year 2000.

First, ENR projects that it would be entirely possible that the energy consumption growth rate could average 0.35 percent per year, as opposed to 0.5 percent under the business-as-usual path. In the year 2000, that would mean a 226-trillion Btu difference between the business-as-usual path and the energy efficiency forecast. (Figure 2)

Under the energy-efficient scenario, the total Illinois energy bill in the year 2000 would be $3.8 billion 1980 dollars below the Business-as-usual energy bill. ENR projects that the state's business would be able to offer 65 thousand more jobs under the energy-efficient forecast than under the business-as-usual scenario. The wide divergence between these two possible energy futures is based on a significant difference in energy efficiency.

The Energy Services Market

The term energy consumer is misleading. The homeowner buys electricity to provide lighting, and the manufacturer buys natural gas to form products, and the farmer buys diesel fuel to power tractors. But what they consume is light, heat and motion. These are services that are provided with the help of

the various energy sources. And the energy sources are, to some extent, interchangeable.

There always has been competition between oil, gas, coal, propane, and other fuels in the energy marketplace; and there always has been competition between the electric and gas utilities for the consumer's dollar.

But in the energy services marketplace, there is another competitor, one that is growing stronger all the time and one that is capturing a growing share of the market. That competitor is efficiency. Energy prices are a powerful aid to selling energy efficiency, and the assumptions behind the business-as-usual path take this competition into consideration.

Consumers have learned that they can buy the same amount of heat by splitting their dollars between insulation and fuel; that they can buy both electricity and better bulbs to generate light at less cost; that they can get more motion out of lighter cars at the cost of less gasoline.

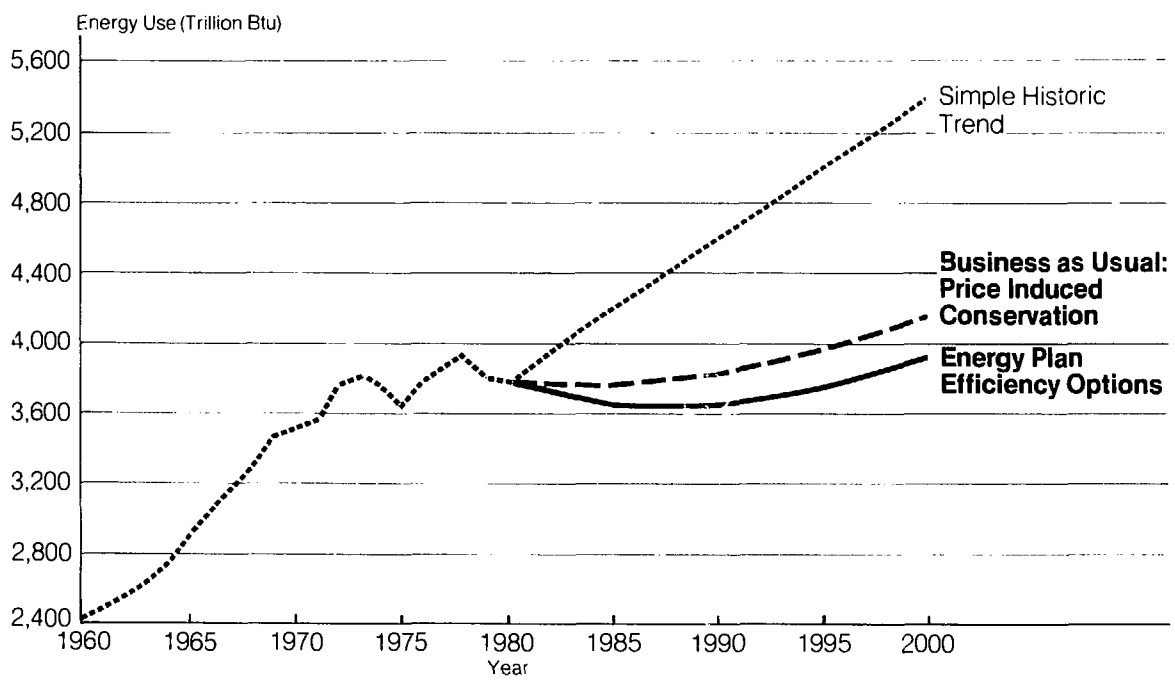
The true price of energy for Illinois goes beyond the dollars spent for imported fuel. As I have stressed, it includes lost opportunities for vital economic activities. The cost is higher than it appears. But energy efficiency, while it does have a price, costs less than it appears. That is because investments in energy efficiency, such as insulation or better machinery or appliances, have a real potential for becoming an investment in the Illinois economy.

Illinois produces coal, oil, and gas here in the state and we can also top solar energy and Illinois' agricultural strength to create fuels. These activities are to the economic benefit of the state. So is energy conservation. It creates jobs. Dollars spent on energy efficiency measures are more likely to remain in the state, thus benefitting the economy.

Comparing the Two Futures

Let us review the benefits of achieving increased energy efficiency under the business-as-usual scenario. Consider individually the residential, commercial, industrial, transportation and agricultural sectors.

A concerted move toward increased energy efficiency could reduce residential energy use by 11.5 percent, compared with projected energy consumption. The average consumer's annual energy bill in the year



Energy Use Trends in Illinois: 1960-2000

Figure 2

2000 would be 185 dollars lower than it would have been.

Although capital expenditures would be required to achieve this efficiency, the cumulative savings in energy costs by the year 2000 would exceed capital costs by 4.5 billion dollars for the state as a whole.

Increased energy efficiency in the commercial sector could save 1.6 billion dollars between now and the year 2000, compared with expected costs under the business-as-usual scenario. This is equivalent to about 140 dollars in additional income to each resident of Illinois, and if invested in Illinois business, could create additional jobs.

Illinois industry is expected to produce goods worth 50 percent more in the year 2000, but with a vigorous energy efficiency effort could at the same time reduce its energy use by 115 trillion Btu's. This would mean a savings of 2 billion dollars in fuel costs after the necessary capital investments are taken into account.

This would be accomplished in large part because of an increase of 30 percent in cogeneration above what is already anticipated. By 2000, new industrial cogeneration could be equivalent to two 400-megawatt power plants and could increase the market for Illinois coal by 7 million tons yearly.

The average automobile traveling to work holds 1.25 persons. By increasing the occupancy average to 1.5 persons, annual highway travel in Illinois could be reduced by 4 billion miles in 1985.

In the aggregate, consumers would save 220 million gallons of fuel in that year, and by the year 2000, saving 720 million dollars from projected fertilizer expenditures in that year. This is the equivalent of 6,900 (1980) dollars for each of the 105,000 farms in Illinois.

It is apparent that improved energy efficiency can bring substantial economic benefits to the state as a whole, as well as to individual consumers of energy services. But there are two degrees to which consumers might embrace energy efficiency and make the necessary capital investments. The lesser degree could be expected under the business-as-usual scenario. It would be the normal, relatively predictable response that would be stimulated by energy prices.

Eliciting the greater response would require more of a stimulus. In many cases, Illinois General Assembly would have to determine which economic interests of the state justified governmental action.

ENR has identified a number of actions as having potential for improving energy efficiency in the

state. In the coming months, ENR will complete an options analysis document, paying particular attention to the role of information, access to capital, and the role the Illinois utility system can play in an energy efficient future. Each of the options we are reviewing will contribute to energy efficiency in some way. Each would augment the behavior and decisions that we expect from consumers in response to rising energy prices.

ENR's work toward a state energy plan has not ignored the questions involving energy resources. In fact, a detailed examination of resource concerns provides the foundation upon which we have been able to build our projections for the future.

Coal and nuclear power will be vital energy resources in the future of Illinois. An energy-efficient future will provide the economic strength to allow us to use those resources and the services they will make possible.

III

ILLINOIS COAL: ENVIRONMENTAL AND ECONOMIC ISSUES

5. Illinois Coal: A Focus For Development

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Policy Landscape

High sulfur coal is a resource with great potential for economic development in Illinois. It is the sulfur content of our coal that presents the greatest barrier to the realization of the economic potential of our reserves.

These facts are not news in Illinois--not to coal companies, not to miners, not to utilities, not to industry, not to state government. Concern for our environment must be balanced with the desire to realize the development potential of high sulfur coal. The balance is necessary today, and the balance will be necessary tomorrow.

The landscape of environmental regulation is changing. So is the landscape of federal synfuels policy and energy research funding. So is the pricing and regulatory structure of the energy marketplace. The problems are the same, but the issues of today and tomorrow are changing. What are the issues in Illinois coal development for the '80's?

- Utilities must be able to use high sulfur Illinois coal, economically and with adequate environmental controls. Sulfur regulations are not going away; the debate over acid rain makes the sulfur issue even more important for utilities. Addressing this issue requires rapid development, demonstration and deployment of current desulfurization technologies--that is to say, scrubbers and coal gasification.
- Industrial steam generation--fired today primarily with gas and oil--must be able to be produced from high sulfur Illinois coal, and industry must be encouraged to use our indigenous energy resource. The industrial market is small relative to utility markets and to the potential in synfuels. But reducing overall energy costs to Illinois industry and retaining energy dollars in Illinois--rather than exporting our dollars to other states or foreign countries--are key areas for the economic health of Illinois. Industrial coal use translates to jobs--mining, operations, and construction--and it means more competitive industries in this state.

- Synthetic fuels must be developed to allow the conversion of high sulfur Illinois coal into clean liquid and gaseous fuels. The present economic problems have slowed the commercial development of synfuels in Illinois. But there is a clear need to promote the siting of synfuels facilities in Illinois, and to set in place the institutions necessary to allow the growth of this new industry with as little socioeconomic and environmental disruption as possible.
- Mid- and long-range research needs to be done to bring coal use technology into the next century. Specifically, basic and applied research in coal desulfurization--resulting in a clean solid fuel-- and research in coal refining--resulting in the maximum use of coal as a hydrocarbon resource--needs to be pursued on an accelerated basis.

For a decade now, the Illinois coal industry, coal users, and state government have worked to face up to the facts about high sulfur coal. And over that decade, state government has put in place programs that can help face up to these facts. What is new and different in state programs to encourage use of high sulfur Illinois coal? Part of what is new and different is the assembly and synthesis of the State's programs into a comprehensive effort. First, here is a synopsis of the Illinois Coal Development Program.

Program Overview

The Illinois Coal Development Program has changed in complexion over the past few years. It is a program geared to the issues of the eighties. The current program is built upon some basic assumptions:

- Environmental regulations may change, but they won't go away. While the state may work to assure that environmental concerns are balanced against economic development, Illinois must set the technical objectives on the basis of environmental standards as stringent, or more stringent, than those found today.
- The role of the federal government in technology demonstrations--in "big buck" federal projects--will be nil. The limited federal role in research and development must be guided to

meet state-level concerns and to guard against Western coal domination.

- Synthetic fuels development will occur on a commercial basis when the economy regains its health; direct federal involvement, beyond the SFC, is not to be expected.
- Technologies for the clean use of high sulfur Illinois coal that are available today must be demonstrated now to assure their adoption in the late '80's and the '90's.
- Basic and applied research must look to supplying new information and technology to put coal on an equal footing with oil and gas as an energy source and chemical feedstock for the coming decades.
- Progress in coal development will require a partnership of Illinois state government and private industry, with strong emphasis on private sector efforts.

The Illinois Coal Development Program has four principal elements: 1) The Illinois Coal Development Bond Fund Program which finances demonstration of coal use technology; 2) A synthetic fuels siting and socioeconomic assessment program; 3) The energy review program for coordinated permitting of major energy facilities, such as synthetic fuels plants; and 4) The coal research program guided by the Illinois Coal Research Board.

Illinois Coal Development Bond Fund Program

The Coal Bond Fund was created in 1974 through the Illinois Coal and Energy Development Bond Act That Act provides a $65 million authorization for the use of state general obligation bonds in support of the development of Illinois coal resources. The program is targeted to the large-scale deomonstration of new environmentally sound technologies using high sulfur Illinois coal. ENR administers the program, with all projects reviewed and approved by the Illinois Energy Resources Commission. Major projects currently being developed through the program include:

- The Allis-Chalmers Kilngas project. The state is contributing $18 million in Coal Bond Funds to the construction of a coal gasification plant based on the Kilngas rotary kiln process at Illinois Power's Wood River generating station. The project will demonstrate low-BTU coal

gasification for retrofit and combined-cycle application in the utilities. A proposal to expand the project to include a combustion turbine element is under ENR review, with announcement of the results of our review and negotiations expected at the end of this month. The gasifier should be operating on Illinois coal next year.

- A second major utility-oriented project is the University of Illinois - Urbana Abbott Power Plant Scrubber demonstration. The State of Illinois, through the joint efforts of ENR, the Capital Development Board, and the U of I will reconvert three boilers at the Abbott power station to burn high sulfur coal with emission control using a Chiyoda CT-121 scrubber. The CT-121 is a regenerable limestone process that ends up with a dry gypsum by-product that is saleable. Coal Bond Funds will support $5 million of the $21.9 million project. The Electric Power Research Institute (EPRI) is participating in the project in research and testing, with a contribution estimated at over $600,000. This technology will provide an excellent demonstration for utilities looking to future capacity or retrofit based on Illinois coal.
- The Combustion Engineering Fluidized Bed Boiler at Great Lakes Naval Station. The state contributed $750,000 to the construction of this FBC project. Demonstration of this technology should result in both industrial and utility applications. The boiler is currently down for repairs, and it is caught in DOE's budget difficulties. The facility has operated for over 2000 hours and test data will soon be available.
- The B. F. Goodrich Circulating Fluidized Bed Boiler demonstration at BFG's Henry plant, where Coal Bond Funds totalling $4.3 million will contribute to the construction of the project. The technology will be supplied by Pyropower Corporation. The boiler is planned for a 125,000 lb/hr steam capacity to supply process heat and steam for the chemical plant. This second generation FBC unit will add greatly to the potential for industrial coal use in the future.
- The Midwest Solvents FBC-Cogeneration demonstration at Pekin, Illinois is moving through final stages of its approval -- it is currently before the Illinois Energy Resources

Commission for review.* The state will contribute $2.5 million in Coal Bond Funds to this project. It will use Foster-Wheeler FBC units based on the experience at Georgetown and will be the first FBC cogeneration plant in the U.S.

The above list of projects reveals that the Coal Bond Fund efforts are targeted at two of the major issues of the eighties: demonstration of technologies for deployment in the utilities and development of technologies that will allow Illinois industry to generate its steam with Illinois coal. The program attempts to show that coal gasification, advanced scrubbers, and first and second generation FBC units are viable options for the clean use of Illinois coal.

Synthetic Fuels Siting and Socioeconomic Programs

Last year ENR completed an environmentally based synfuels siting survey. This year we are beginning to develop site specific documents that will allow synfuels developers to move ahead quickly in their site selection process. We are aiming to fulfill two compatible objectives with these efforts:

- To encourage synfuels developers to site in Illinois by making it as easy as possible.
- To promote environmentally and socially sound siting decisions, so that synfuels can develop with the least possible negative impact and the least possible delay.

When a developer has selected a site, ENR provides assistance in assessing potential socioeconomic impacts and in developing plans to mitigate impacts. ENR has already begun to work with MAPCO's White County project on an assessment analysis, and has made a commitment to the local community to help plan for impacts.

ENR also is working to assure that, as synthetic fuels develop in Illinois, the majority of impacts are beneficial. Economic development doesn't have to lead to social disruption or severe environmental degradation.

*The project was approved for funding.

The Energy Review Program

In conjunction with siting and socioeconomic work, ENR has developed a Coordinated Review Process for major energy facilities. The process is set in place now. The objective is to improve the permitting process for synthetic fuels plants. The concept of the process is to get all of the parties involved in the project to sit down together to work out the procedural and the substantive issues of permitting a synfuels plant. This includes the project developer; permitting agencies at the federal, state and local levels; public interest groups and concerned citizens. The concept has worked in other states - most notably Colorado. The result is quicker permitting and less litigation on major projects. It can work in Illinois.

Illinois Coal Research Board

The most recent addition to the Illinois Coal Development Program is the Illinois Coal Research Board. The board was created by law late in 1981. Now, one year later, the Board has solicited, reviewed and selected $1.3 million in research projects that will develop the information and technology into the next century. With the decline in federal funding and tough sledding for coal research in the private sector, additional state funding of coal research is both timely and significant.

The Board is hard-working and committed to their goal. The first meeting of the Board was in late spring of 1982, and they began soliciting projects in May and June. On September 1-2, the Board met to make decisions on the projects to be selected. Their review process was thorough and reflected a tremendous effort by the Board members--as well as ENR staff--to come to some tough decisions. The dedication of the Board has already been recognized. And when Governor Thompson met with the Board on September 2, he signed this year's special appropriation for the Board and pledged his continued support and continued funding of their efforts.

On the substantive side, the Coal Research Board has made great strides in establishing research priorities. The first priority of the Board has been placed on the desulfurization of coal as a solid fuel. Other high priority items are continued refinement of characterization of Illinois coal and new uses for it.

The largest portion of Board funds will go to develop the Center for Research on Sulfur in Coal. This will be a joint effort by the Illinois Geological Survey, the University of Illinois at Urbana and Southern Illinois University at Carbondale. The Center is moving forward to establish a firm foundation in research and information in the areas of coal desulfurization and coal refining. Projects funded by the Board are listed in Table 1.

Summary

The Illinois Coal Development Program has integrated a number of efforts in state government developed over the last decade. The program provides the focus needed for the development of Illinois' high sulfur coal resource. The current program brings together key leaders in government, industry and public interest groups to assure that the necessary balance of economic development, environmental protection and social well-being can be achieved. Illinois state government is in a position to be a full partner in that effort.

TABLE 1
PROPOSALS SELECTED FOR FUNDING
BY THE ILLINOIS COAL RESEARCH BOARD

Applicant and Title	Funding Approved by Coal Research Board
Eastern Illinois University "Chemical Characterization of Functional Groups in Illinois Coal Cleaved by Pyridinium Iodide"	$ 21,772.00
Illinois State Geological Survey Southern Illinois University University of Illinois - "Center for Research on Sulfur in Coal"	850,000.00
Southern Illinois University Illinois State Geological Survey "Desulfurization of Illinois Coal by in situ Preparation of Iron Sulfide Catalysts"	118,630.00
Illinois State University "Organic Sulfur Reduction in Illinois Bituminous Coal via Carboxylation Reactions with Alkali in Protic Solvents"	53,357.00
University of Chicago "The Role of Sulfur Compounds in Coal Conversion Reactions"	132,023.00
Institute of Gas Technology "Microbiological Desulfurization of Illinois Coal"	89,762.00
Institute of Gas Technology "A Sonic Method for Coal Cleaning"	77,154.00
	$1,342,698.00

6. Acid Rain: The Path from Research to Public

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The purpose of this paper is to summarize the status of scientific knowledge on atmospheric deposition and its effects and to relate the knowledge accumulated to the processes of public decision-making about energy use and environmental quality.

Present Status of Knowledge

The following items of information may be helpful in considering the causes, consequences, and possible strategies for management of acid deposition:

Figure 1 presents a map showing the distribution of acid precipitation across the United States and Canada in 1980. This map was developed by the NADP

Figure 1

and CANSAP (Canadian) monitoring programs. Please note: (1) that precipitation with an average annual pH of 4.6 (10 times more acid than "normal") is occurring in nearly every state and province of eastern North America; and (2) that precipitation with an average pH of 4.1-4.3 (40-50 times more acid than "normal") is occurring in large areas of the provinces of Ontario and Quebec in Canada and in the following states of the United States: Illinois, Michigan, Indiana, Ohio, Kentucky, West Virginia, Maryland, Pennsylvania, New Jersey, New York, Connecticut, Rhode Island, Massachusetts, Vermont, New Hampshire, and Maine.

Figure 2 presents a map showing the distribution of precipitation- monitoring sites in the National Atmospheric Deposition Program in the various states of the United States. Please note that this program is now approaching the number (150) and distribution of collection sites (nationwide) that will be necessary to provide a continuing, accurate, and reliable record of change in the chemical climate of the United States.

Figure 3 reveals two maps showing the distribution of sensitive surface waters (left) in relation to major industrial sources of sulfur dioxide in North America (right). Please note that the sensitive water of North America are well within the average daily travel distance of air masses from the major sources of sulfur and nitrogen oxides in this region. The distribution of sources of NO_x emissions are not greatly different from those for SO_2 emissions (from Galloway and Cowling, 1978 and Graves 1980).

Figure 4 is a map of North America published recently by Bette Hileman in Environmental Science and Technology 16(6): 323A-327A, 1982). Please note that the region with rainfall of the lowest pH includes nearly all states with the highest SO_2 emissions.

Appendix 1 contains a "Status Report on Acid Deposition." This series of 41 documented statements provides a general introduction to prinicples every energy and environmental decision-maker needs to know about acid deposition and its ecological consequences. This Status Report summarizes our present knowledge about many aspects of the acid deposition problem.

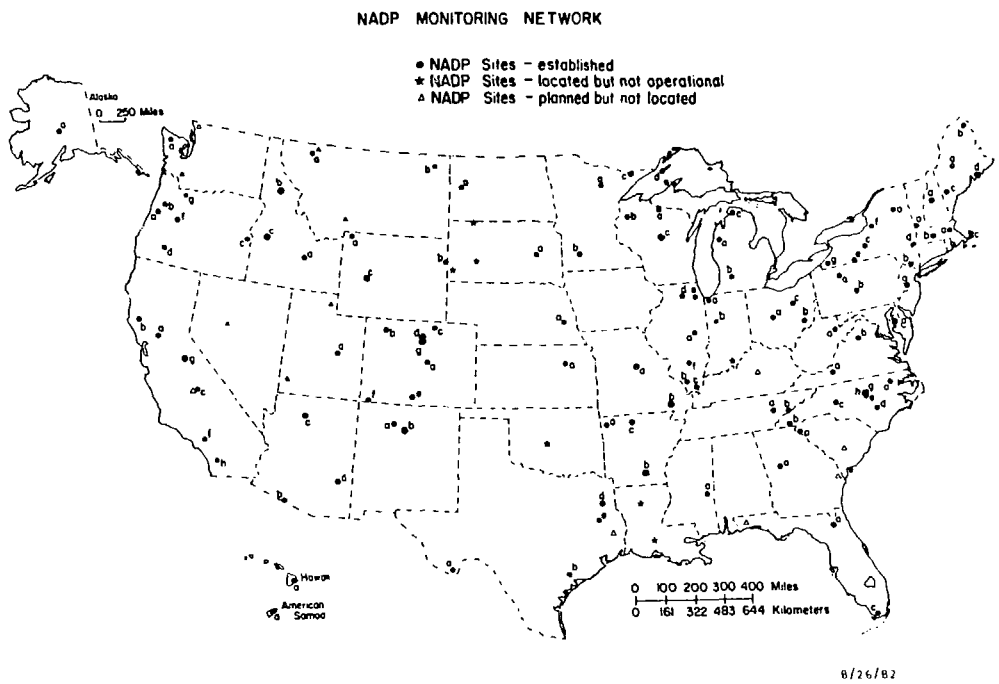
NADP MONITORING NETWORK
• NADP Sites – established
★ NADP Sites – located but not operational
△ NADP Sites – planned but not located
Alaska
0 250 Miles
Hawaii
American Samoa
0 100 200 300 400 Miles
0 161 322 483 644 Kilometers
8/26/82

Figure 2

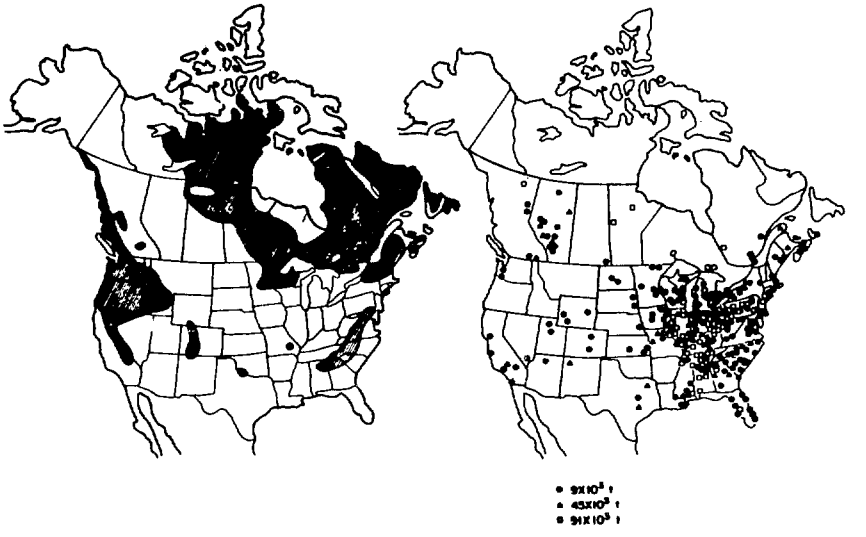

Figure 3

Please note especially:

- Statements 1, 2, 3, 4, 7, 8, 9, and 12 under Atmospheric Chemistry, Transport, and Deposition;
- Statements 14, 16, and 19 under General Effects on Ecosystems;
- Statements 21, 22, 24, and 26 under Effects on Aquatic Ecosystems;
- Statements 28-30 under Effects on Agricultural Crops and Forest; and
- Statements 40 and 41 under Effects on Water Quality.

Appendix 2 presents a suggested Framework for Policy Decisions Leading to Possible Management of Acid Deposition and its Effects. This list of seven steps has been recommended to the National Acid Precipitation Assessment Program (NAPAP) as a means to insure an adequate policy focus for research sponsored by the NAPAP.

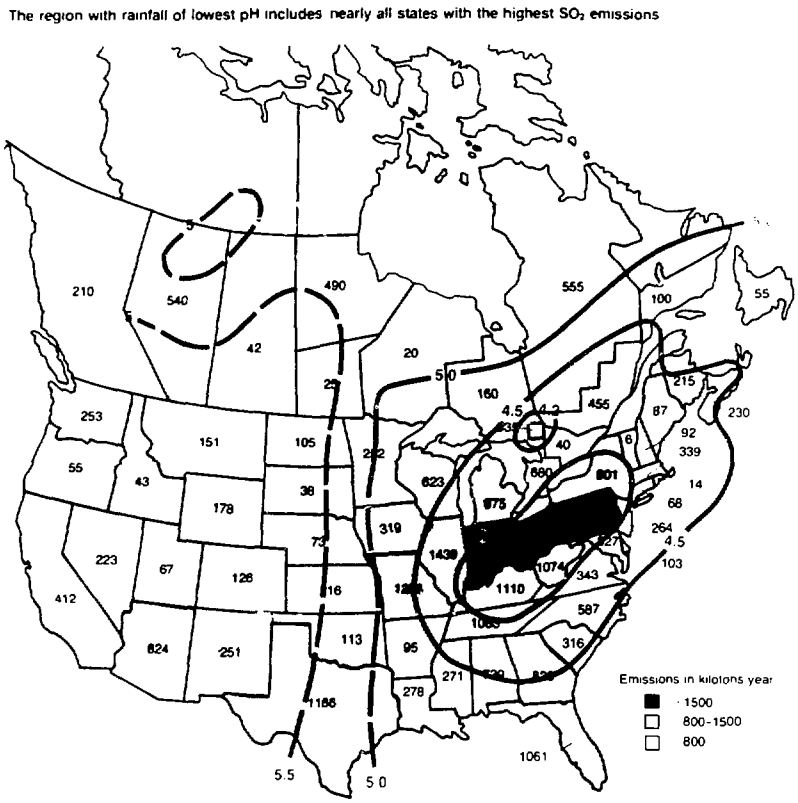

Figure 4

SOURCE: Article by Brand L. Niemann to be published by Ann Arbor Science in November 1982 in the Proc. Symp. Acid Precipitation. Spatial variation of precipitation-amount-weighted mean pH in North America in 1980 compiled from Canadian (CANSAP, APN) and American (NADP, MAP3S) networks by the U.S.-Canada Work Group 2

General Comments and Conclusions

The various maps and statements shown in Figures 1-4 and Appendix 1 provide background for the following general comments and conclusions:

1) Human activities of many types are changing the chemical climate of North America. Some of these changes are beneficial for agriculture and forestry because they provide valuable nutrients for the growth of crops and trees or accelerate the natural weathering of soil minerals. Other changes are detrimental because they cause stress in plants and animals, alter water quality, aggravate nutrient deficiencies in soils, or accelerate the natural weathering or corrosion of man-made structures and materials. (Appendix 1)

2) Acid precipitation is occurring in very large areas across the North American continent (Figure 1). Dry deposition of acidic and acidifying substances is also occurring in large regions across the continent, but little reliable data are currently available on loading rates and geographical trends in various regions. Developing proper methods for measurement of dry deposition is a priority goal of the National Acid Precipitation Assessment Program.

3) The areas receiving highly acid precipitation (average annual pH between 4.1 and 4.6, Figure 1) include many regions in which surface waters and aquatic life are sensitive to and/or are presently being affected by acid precipitation (Figure 3).

4) Much more is known at present about the nature, geographical location, and extent of detrimental effects of acid deposition on fish and other aquatic life, and drinking water quality than about possible effects on agricultural crops and forests. As indicated in a recent National Research Council report (Cowling 1981), "The effects of acid precipitation and associated metal ion toxicity on aquatic ecosystems are sufficient to warrant preliminary formulation of management and ameliorative strategies" (Appendix 1, statements 21, 24, 26, 40, 41) {but} "the potential effects of acid precipitation on terrestrial organisms are not understood well enough to justify consideration of management strategies at this time" (Appendix 1, statements 15, 17, 28, 31).

5) Gaseous emissions of sulfur and nitrogen oxide from combustion of fossil fuels are the princi-

pal sources of acidifying substances (Figure 3 and Appendix 1, statements 2,7). These substances which are emitted mainly from power plants, smelters, industrial boilers, and transportation vehicles are deposited in urban-industrial, rural, and remote areas throughout eastern North America (Figure 1 and Appendix 1, statements 1, 2, 7, 9).

6) The several states of the United States and provinces of Canada vary greatly in the total amounts of their sulfur and nitrogen oxide emissions and in their proximity to acid-sensitive geographical regions (Figures 3 and 4).

7) The distance of transport of gaseous emissions leading to wet and dry deposition of acidifying substances is typically of the order of several hundred miles. Substantial vertical and horizontal mixing of air pollutants from many different and geographically separate sources occurs during transport over these distances (Figures 1 and 3; Appendix 1, statements 1, 2, 8); thus, the direction of transport often is not the same as the direction of so-called prevailing winds. Also, atmoshperic emissions of sulfur dioxide, nitrogen oxides, toxic metals, and other waste products in all states of the eastern United States and in all provinces of eastern Canada contribute to the deposition and accumulation of strong acids and other toxic substances in each of the major sensitive regions of eastern North America (Figures 3 and 4).

8) Acid stress in aquatic ecosystems and mobilization of toxic metals into surface waters almost always are due to the cumulative effects of wet and dry doposition over a period of many weeks (prolonged summer drought), several months (winter snow accumulation), or even several years (gradual titration of clearwater lakes). For this reason long-term regional, seasonal, and annual trends in the chemical climate of North America are much more important in determining biological effects on aquatic ecosystems then the chemistry of specific meteorological events (Appendix 1, statements 14, 21, 22 24, 26, and 40).

9) Approximately the same extent of acidification of an ecosystem is achieved whether the acidifying substances are deposited as gases, fine aerosols or coarse particles, or as dissolved substances in precipitation. This is true

because the original emmissions and their intermediate products are rapidly converted to $SO_4^=$ or NO_3^- when they contact moist plant, animal, or soil surfaces (Appendix 1, statements 10,11, 12).

10) It is generally accepted that all emissions of sulfur and nitrogen oxides return to the surface of the earth--either over the continents or over the oceans. It is also generally accepted that (a) changes in emissions of sulfur and nitrogen oxides will result in corresponding linear changes in amounts of dry deposition and (b) that the extent of expected deviations from linearity for wet deposition will probably vary inversely with distance from major emission sources and directly with the density of emission sources.

This same idea was summarized very succinctly in the recent report of an international group of atmospheric scientists at the 1982 Stockholm Conference on Acidification of the environment: "What goes up must come down. This holds true for a very large region. Specific areas within a region might experience significant smaller or larger decreases in deposition from a general decrease in emmissions. However, the total deposition over the whole industrialized region would decrease approximately in proportion to the reduction in emissions."

11) According to the recent Atmospheric-Biosphere Report of the National Academy of Sciences (NAS, 1981), emissions of sulfur and nitrogen oxides should be decreased by an amount sufficient to maintain the average annual acidity of precipitation above 4.6 or 4.7. This estimate of a biologically "acceptable" acidity of wet deposition is based on surveys of fish populations and water chemistry in acidified, partially acidified, and non-acidified lakes and streams in Europe and North America. A similar suggestion has been made in a recent draft of the Impact Assessment Working Group of the United States-Canada Memorandum of Intent on Transboundary Air Pollution: "Wet sulfate loading values of 11-20 kg/ha/yr have been suggested as being protective for the majority of surface waters." Keeping the pH of wet deposition in sensitive regions above 4.7 or the wet sulfate loading below 20 kilograms per hectare per year will require significant (30-50%) decreases in emissions of sulfur and

nitrogen oxides throughout the eastern United States and southeastern Canada (Figures 3 and 4).

12) It follows from the climatological and biological facts presented in statements 3-11 above, that a decreased-emission strategy to protect sensitive surface waters and aquatic life in any given region within eastern North America will require significant decreases in air emissions of sulfur and possibly also nitrogen oxides in most of the industrial regions of eastern North America. Some additional research may be needed to determine the extent to which general changes in emissions in one state or province will alter the chemistry of decomposition in other states and provinces. The next important scientific issue is to determine where and by how much will it be necessary to decrease emissions of acid deposition precursors in order to achieve the biologically "acceptable" extent of decrease in deposition that is recommended. A scientific committee to study this very question has recently been established by the National Academy of Sciences.

13) Each step in the "Suggested Framework for Policy Decisions" (Appendix 2) involves uncertainties that are analogous with those that surrounded the debates about the role of phosphorus in the eutrophication of Lake Ontario and Erie in the early 1970s. The experts then could not agree. Some said a 40% decrease in loading would be needed. Others said 75%. Still others said nitrogen was to blame, not phosphorus. Environmentalists warned of "possible irreversible damage." Industry said more research was needed. Finally a political decision was reached--a plan should be developed. More debates were held. A theoretical model was used to predict that a 50% decrease in loading might be sufficient. Under conditions of substantial uncertainty a management plan was finally implemented. After some time the lakes began to improve. The theoretical estimate was too low but with some further adjustments the plan worked and the lakes are now on the road to recovery.

14) After a decision is made to proceed with preliminary evaluation of policies to protect sensitive regions from acid deposition, it probably will take at least five years to debate the scientific and management issues suffi-

ciently to formulate an appropriate management plan. Also, at least another five years probably will be required to achieve an actual reduction in emissions. During the period of debate, new biological, atmospheric, chemical, and meterological insights will be developed which will help refine whatever management strategies may be recommended. Therefore, it seems prudent that we continue the present debate in the Congress, in the Parliament, in the board rooms, and in the energy conferences of this continent. While do ing so, we should also recognize that research is continuing and that a progressively better scientific foundation is becoming available upon which to make decisions under conditions of continuing uncertainty.

Summary

Much has been learned in recent years about acid deposition and its effect on public welfare. But much also remains to be learned about certain aspects of the problem and possible strategies for its solution. Today, public concern about acid rain is at an all-time high in many parts of the world. The recent Presidential and Congressional initiatives in acid rain research in the United States have culminated in the formation of a Federal Interagency Task Force on Acid Precipitation and the recently implemented Federal Acid Precipitation Assessment Program. These initiatives call for a carefully coordinated program of policy-oriented research (Appendix 2). Both of these initiatives and the current air pollution treaty negotiations with Canada offer increasing hope that the United States will do its part, together with Canada, to develop in a timely way the additional knowledge that is needed.

Our present energy and environmental policies are resulting in change in the chemical climate of the earth. Important changes are taking place in the lakes, streams, fields, forests on which both the abundance and the quality of our life depends. Wise management of these resources require communication among biologists, hydrologists, atmospheric chemists, climatologists, regulatory strategists, and both industrial and political leaders in the United States and Canada. Let us continue that communication by focusing our collective knowledge on the development of more adequate plans for management of air quality and its effects on plants, animals, soils, surface

waters, and materials. The current debates about revision of the Clean Air Act and an air pollution treaty with Canada provide two important occasions for such collective thinking.

Appendix 1

A STATUS REPORT ON ACID DEPOSITION AND ITS ECOLOGICAL CONSEQUENCES AS OF APRIL 1981

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Ellis Cowling has been engaged in acid precipitation research for the past 10 years. At present he serves as Chairman of the National Atmospheric Deposition Program (NADP), Program Director of the EPA-NADP-NCSU Acid Precipitation Program, Associate Dean for Research in the School of Forest Resources, and Assistant Director of the North Carolina Agricultural Research Service at North Carolina State University (NCSU). This status report is a product of interactions with scientists in each of these organizations and in the Swedish and Norwegian programs of research on acid precipitation. Critical review of this report by the following colleagues is acknowledged with appreciation: Svante Oden, Lars Overrein, Floyd Edler, Douglas Whelpdale, Gene Likens, James Galloway, George Hendrey, Eville Gorham, William McFee, Jay Jacobson, Norman Glass, and Orie Loucks.

The following is a summary of the general status of knowledge about acid deposition and its ecological consequences as of April 1981. In most cases these statements are a synthesis of observations and inferences derived from many independent investigations. It is beyond the scope and purpose of this account to provide rigorous and complete documentation; thus only a few key investigations are cited for each statement. Complete documentation can be obtained by consulting the original literature, access to which is provided by the following reviews and documents: Abrahamsen, 1980; Almer et al., 1974; Altshuller and McBean, 1979, 1980; Ambio, 1976; Bolin et al., 1972; Braekke, 1976; Cowling, 1980, 1981; Dochinger and Seliga, 1976; Drablos and Tollan, 1980; Galloway et al., 1978; Gorham, 1976; Hendrey, 1978; Howells, 1979; Husar et al., 1978; Hutchinson and Havas, 1980; Likens, 1976; Likens et al., 1979; Malmer, 1973; NAS, 1975; Oden, 1968, 1976; Overrein et al., 1980; and Reuss, 1975.

Atmospheric Chemistry, Transport and Deposition

1. Acid precipitation (rain, snow, hail, dew, fog, frost) is occurring in large regions of the eastern United States and Canada, Europe and Japan. It has also been reported in certain urban and rural areas in the western United States and Canada and may occur in other regions of the world (Oden, 1968; McColl and Bush, 1978; Likens et al., 1979; Lewis and Grant, 1980).

2. This widespread occurrence of acid precipitation results in large part from man-made emissions of oxides of sulfur and nitrogen. These substances are transformed in the atmosphere to sulfuric and nitric acids, transported over great distances, and deposited on vegetation, soils, surface water and materials (Smith, 1872; Bolin et al., 1972; Likens, 1976).

3. Acid precipitation is only one mechanism by which air pollutants and other substances are transferred from the atmosphere onto plants, soils, surface waters, and structural materials. The other methods of deposition include a) absorption and adsorption of gases, and b) impaction and gravitational settling of fine aerosols and coarse particles. These other processes are called dry deposition (Junge and Werby, 1958; Galloway and Cowling, 1978).

4. The acidity (or alkalinity) of precipitation is measured in terms of pH units -- the negative logarithm of the concentration of hydrogen ions. Carbon dioxide combines with water in the air to form a dilute solution of carbonic acid at about pH 5.6. For this reason, acid precipitation is arbitrarily defined as precipitation with a pH value below 5.6. Because pH is a logarithmic scale, each unit change in pH represents a ten-fold change in acidity (Oden, 1968; Likens, 1976).

5. Evidence for the occurrence of long-term increases in the acidity of precipitation in North America includes the following: a) changes in average annual pH value of precipitation in the years 1955-56 and 1975-76, b) changes in the alkalinity of surface waters; an especially valuable data set of this sort is available for the Hinckley Reservoir near Utica, New York between 1924 and 1980, c) changes in

the amounts and patterns of fuel use in the United States and Canada since the industrial revolution began about 1850; at present, about 95% of sulfur emissions in eastern North America are from man-made sources, and d) changes in the sulfate and lead content of Greenland ice also since about 1850 (Beamish and Harvey, 1972; Cogbill and Likens, 1974; Cragin et al., 1975; Cronan and Schofield, 1979; Galloway and Whelpdale, 1979).

6. The ratio of sulfate to nitrate ions in precipitation varies from time to time and from place to place. In much of eastern North America the average equivalent ratio of sulfate to nitrate varies from 3.3:1 in summer to about 0.7:1 in winter. The average annual ratio of sulfuric to nitric acids is currently about 2:1; but nitric acid is becoming progressively more important relative to sulfuric acid (Likens, 1976; Likens et al., 1979; Galloway and Likens, In press).

7. Tall stacks at power plants and smelters decrease nearby groundlevel concentrations of SO_2 and NO_x but simultaneously increase the geographical area of acid deposition. Removal of alkaline particulate matter from stack emissions also increases the acidic character of atmospheric pollutants and therefore the acidity of atmospheric deposition. (NAS, 1975; Braekke, 1976).

8. Analyses of air-mass movements and chemical transformations in the atmosphere indicate that acid precipitation in one state or region results in part from emissions into the atmosphere in other states or regions, often many hundreds of kilometers from the original source of the emissions (Oden, 1968; OECD, 1977; Galloway and Whelpdale, 1979; Altshuller and McBean, 1979, 1980; Husar and Patterson, 1980; Lyons, 1980).

9. Contemporary precipitation in industrial regions of the world is acidified mainly by man-made emissions of gases and particulate matter. Major anthropogenic sources include combustion of fossil fuels (especially coal and oil), certain industrial processes (especially smelting of ores), exhausts from internal combustion engines, and nitrogen fertilization of agri-

cultural and forest land (Bolin et al., 1972; Kovda, 1975; Likens, 1976).

10. Changes in the acidity of precipitation are reflections of changes in the balance between the positively and negatively charged substances in precipitation. The more hydrogen ions (H+ ions) the greater the amount of acidity. Thus, to understand the acidity of precipitation, it si essential to measure all the major anions and cations in precipitation (especially hydrogen, sulfate, nitrate, and ammonium ions, but also including potassium, sodium, calcium, magnesium, chloride, bicarbonate, sulfite, and phosphate ions) (Likens, 1976).

11. All of the major anions and cations transferred into ecosystems when it is raining or snowing (wet deposition) also are contained in the gases and particulate matter that are transferred from the atmosphere into ecosystems when it is not raining or snowing (dry deposition). Thus, in a chemical mass balance sense, it is both impossible and unrealistic to distinguish the biological effects of "acid precipitation" (wet deposition)*from* the biological effects of dry deposition (Tamm, 1958; Kovda, 1975; Oden, 1976).

12. Some substances (such as ammonium sulfate) which themselves are not acidic can cause the acidification of soils when they are taken up by plants or modified by soil microorganisms. Thus, the concept of "acidifying precipitation" must be added to the concept of "acid precipitation" (Oden, 1976).

13. The potentially injurious substances in dry and wet deposition include not only acidic substances but also certain toxic gases and organic substances (notably pesticides) as well as various other inorganic substances (such as radioactive materials and asbestos fibers) or heavy metals such as manganese, zinc, copper, iron, molybdenum, boron, chlorine, flourine, bromine, iodine, aluminum, arsenic, mercury, lead, nickel, cadmium, vanadium, etc. (Gorham and Gordon, 1960; Gorham, 1961; Tyler, 1972; Hutchinson and Whitby, 1974; Kovda, 1975; Galloway et al., 1980).

General Effects on Ecosystems

14. The elements listed above are essential micronutrients needed by plants in small amounts. At higher concentrations, however, each of these same elements (and all the others) can be toxic to plants and animals.

    Furthermore, the acidity of precipitation can affect the solubility, mobility, and toxicity of certain of these elements. These substances can affect the following: a) the foliage and roots of plants, b) animals or microorganisms that may ingest of decompose these plants, c) animals (including man) which may drink water containing these elements, and d) animals (especially fish and other aquatic organisms) that live in chemical equilibrium with waters containing these substances (Ambio, 1976; Oden, 1976).

15. Significant quantities of plant nutrients, including nitrogen and sulfur, are being added to soil in dry deposition and in precipitation. These atmospheric inputs of beneficial nutrient elements are especially important in forests and rangelands were nutrients from other sources are scarce where fertilization by man is not a normal management procedure (Hooke, 1687; Tamm, 1958; Wittwer and Budovac, 1969; Cowling, 1980).

16. Short-term fertilization effects due to atmospheric deposition of ammonial and nitrate tend to offset long-term nutrient leaching and other detrimental effects of acid precipitation on forest ecosystems. Negative effects of atmospheric deposition on forest growth are most likely when nutrient deficiencies or imbalances are increased by acid deposition (Abrahamsen, 1980).

17. The net effect of atmospheric deposition can be beneficial or injurious to plants and animals depending on the chemical composition of the deposition (wet and dry), the duration and intensity of deposition episodes, the species and genetic characteristics of the organisms on which substances are deposited, and the physiological condition, structure, and stage of maturity of the organisms (Grahn et al., 1976; Abrahamsen, 1980; Cowling, 1980; Lee et al., 1980).

18. Damage or injury to aquatic or terrestrial organisms is most likely when a particularly sensitive life form or life stage developing in poorly buffered waters or soild coincides (in time and/or space) with major episodic inputs of acid precipitation or other injurious substances (Borgstrom and Handray, 1976; Leivestad et al., 1976; Likens et al., 1976; Hall et al., 1980)

19. Regions of greatest sensitivity to acid precipitation usually are recently glaciated, with large areas of exposed granitic (crystalline) and other non calcarious bedrock and thin soils that are low in buffering and cation exchange capacity. The sensitive regions in North America include parts of New York, New England, large areas of Ontario, Quebec, and the maritime provinces of Canada, northern Minnesota, Wisconsin, and Michigan, parts of southern Appalachia and Florida, and large parts of Washington, Oregon, California, and Idaho. (Reuss, 1975, McFee, 1978; Galloway and Cowling, 1978; Abrahamsen, 1980).

20. Terrestrial and aquatic ecosystems are so intimately linked that it is both impossible and unrealistic to consider the effects of acid precipitation in aquatic ecosystems without considering its effect on terrestrial vegetation, soils, and the geology of the drainage basin (Braekke, 1976; Olen, 1976).

Effects on Aquatic Ecosystems

21. Acids and other soluable substances contained in polluted snow are released as contaminated meltwater during warm periods in winter or in early spring. The resulting release of pollutants can cause major and rapid changes in the acidity and other chemical properties of stream and lake waters. Fish kills are a dramatic consequence of such episodic inputs into aquatic ecosystems (Oden and Ahl, 1970; Leivestad et al., 1976).

22. Acid precipitation changes the acidity/alkalinity of lake and stream waters from conditions that are favorable for fish and other aquatic organisms to conditions that inhibit reproduction and/or recruitment of populations of fish and fish-food organisms (Hendray and

Wright, 1976; Henriksen, 1979; Leivestad et al., 1976; Henriksen, 1980).

23. In nutrient-poor lakes and streams between pH 6.0 and pH 5.0, reproduction of certain species of aquatic organisms is inhibited; below pH 5.0, populations of many freshwater fish will go to extinction (Beamish and Harvey, 1972; Dickson et al., 1973; Leivestad et al., 1976; Schofield, 1976).

24. Interference with normal reproductive processes in fish populations is induced not only by acidity itself but also by increased concentrations of certain cations - notably aluminum - in acidified lake and stream waters. Aluminum compounds vary greatly in toxicity to fish and other aquatic life. In general, ionic forms of aluminum are more toxic than aluminum complexed with organic matter (Hultberg and Grahn, 1976; Cronan and Schofield, 1979; Driscoll, 1980).

25. Reproduction of frogs and salamanders also is inhibited by atmospheric acidification of surface waters (Pough, 1976; Hagstrom, 1977).

26. As of 1980, hundreds of lakes in the Adirondack region of New York State, and many hundreds of lakes in various parts of southern Ontario and Quebec were showing acid stress in the form of diminished populations or extinction of fish populations. Lakes and streams in other regions of the United States and Canada also are vulnerable to stress by acid precipitation. These regions include northern Minnesota, Wisconsin, and Michigan; parts of southern Appalachia and Florida, and large parts of Washington, Oregon, California and Idaho and parts of the Canadian Maritime Provinces (Beamish and Harvey, 1972; Schofield, 1976; Galloway nad Cowling, 1978; Altshuller and McBean, 1979; Hendrey et al., 1980).

Effects on Agricultural Crops and Forests

27. In certain industrial regions of the world, substantial damage to forests and agricultural crops is caused by the dry deposition of toxic gases. Sulfur dioxide, ozone, oxides of nitrogen, fluoride, and hydrogen chloride cause serious economic damage to crops and forests

that must be considered together with the possible effects of acid deposition. Recent experiments have shown that a combination of acid precipitation and ozone caused greater reduction in yield of soybeans than ozone alone (Heck and Brandt, 1977; Shriner et al., 1980; J. Trioiano, personal communication).

28. Direct and indirect damage to crops and forests have been reported in laboratory, greenhouse, and field experiments in which synthetic rain equivalent (in chemical composition and rate of deposition) to natural rains has been applied. These biological effects include the following:

- Induction of necrotic lesions and other morphological changes in foliage (Shriner, 1978; Evans and Curry, 1979)
- Loss of nutrients due to leaching from foliar organs (Wood and Bormann, 1974)
- Predisposition of plants to infection by bacterial and fungal pathogens (Shriner, 1978)
- Accelerated erosion of waxes on leaf surfaces (Shriner, 1976)
- Inhibition of nodulation of legumes leading to decreased nitrogen fixation by symbiotic bacteria (Shriner and Johnston, 1980)
- Reduced rates of decomposition of leaf litter leading to decreased mineralization of organically-bound nutrients (Abrahamsen, 1980)
- Inhibited formation of terminal buds and increased mortality of pine seedlings (Matziris and Nakos, 1977)
- Both decreased and increased yield of certain agricultural crops (Evans and Lewin, 1980; Evans et al., 1980; Lee et al., 1980)
- Interference with normal reproductive processes (Evans and Conway, 1980).

29. Various specific biological effects of simulated acid rain have been demonstrated in controlled field and laboratory experiments (see item 28 above), but reliable evidence of economic damage to agricultural crops, forest and other vegetation, and to biological processes in soil by naturally occurring precipitation has been reported only rarely (Jonsson and Sundburg, 1972; Galloway et al., 1978; Cowling, 1980; Ulrich and Khanna, 1980; Tomlinson, 1981).

30. Recent experiements in Germany have demonstrated a significant correlation between amount of

soluble aluminum in forest soils, death of feeder roots in spruce, fir, and beech forests, and widespread decline in the growth of these forests. Acid precipitation and dry deposition of acid-yielding subs nces have been postulated as a probable cause of these coincident effects (Ulrich et al., 1980; Schuck et al., 1979; Tomlinson, 1981).

31. Mushrooms, mosses, lichens, and other lesser vegetation in forest accumulate heavy metals, from the atmosphere, especially lead and cadmium. Wildlife feeding on these plants themselves accumulate the metals sometimes making both the plants and the wildlife hazardous for human consumption (Munshower, 1972; Huckabee and Blaylock, 1974; Tyler, 1980).

Effects on Soils

32. The consequences of acid inputs to soils vary greatly, depending upon the rates and recent history of atmospheric acid inputs, the character of the vegetation, natural rates of acid formation in the soil, and the physical-chemical properties of the soil (Wiklander, 1973; McFee, 1978).

33. Soil acidification increases leaching of exchangeable plant nutrients such as calcium, magnesium, postassium, iron, and manganese, and increases the rate of weathering of most minerals (Overrein, 1972; Reuss, 1975; Oden, 1976).

34. Acidification decreases the rate of many soil microbiological processes such as nitrogen fixation and breakdown of organic matter. Various processes important in nutrient cycling, and critical in most ecosystems, are known to be inhibited by lowering soil pH. Included are the following: nitrogen fixation by Rhizobium bacteria on leguminous plants, by actinomycetes on some nonleguminous plants, and by certain blue-green algae and bacteria; mineralization of nitrogen from forest litter; nitrification of ammonium compunds; and overall decay rates of forest floor materials (Reuss, 1975; Braekke, 1976; Francis et al., 1980; Shriner and Johnston, 1980).

35. Atmospheric deposition of heavy metals also inhibits certain microbial processes in forest litter, especially decomposition of organic matter (Braekke, 1976; Tyler, 1976).

36. Acidification of soils reduces the availability of phosphorus to plants and increases the solubility of other elements, some of which may be toxic to plants. Aluminum is the most abundant toxic element in most forest and agricultural soils. Increasing soil acidity leads to greatly increased solubility and toxicity of aluminum to many crop and forest plants (Oden, 1976; Tomlinson, 1981).

37. Soils differ greatly in their susceptibility to acidification. Calcareous soils are unlikely to be damaged by acid inputs, but may be affected by metal deposition. Soils with low cation exchange capacity and degree of base saturation are very susceptible to increased acidification (Reuss, 1975; McFee, 1978).

38. Large quantities of hydrogen ions are added to soils as acid precipitation and as a result of cation uptake processes and both soil-amendment and fertilization practices. Acidification by these processes can be controlled by normal management practices in cultivated soils. But large areas of North America and Europe are not cultivated and have soils that are poorly buffered and therefore susceptible to further acidification. Many of these soils occur in forest and wilderness areas (Reuss, 1975; Oden, 1976.)

Effects on Water Quality

39. The chemical composition of lake, stream, and groundwaters is determined in part by the chemical composition of precipitation and dry deposition. The chemical composition of precipitation is modified by chemical and biological weathering and exchange processes as precipitation 1) washes over vegetation, 2) percolates through the soil, 3) interacts with the underlying bedrock of the drainage basin in which the precipitation occurs, and 4) runs off over the soil surface (Braekke, 1976; Oden, 1976).

40. Acid precipitation increases the solubility and mobility of many cations in soil. This increases the concentration of toxic metal cations including aluminum, manganese, and zinc in the soil solution. It also increases the leaching of nutrient cations including potassium, calcium, and magnesium, etc. These toxic and nutrients ions are transferred from soils into surface and groundwaters (Braekke, 1976; Oden, 1976).

41. Acidification of groundwaters has been found in western Sweden and attributed to long-term changes in the acidity of precipitation. As a result, hundreds of shallow dug wells and deeper drilled wells for home and farm buildings have shown acidities in the range between pH 4.0 and pH 6.0. A strong positive correlation has been found between the acidity of the well water and the content of metal ions including copper, zinc, lead, manganese, and aluminum. High concentrations of these metal ions in drinking water are hazardous to the health of people and livestock. In some cases, accelerated corrosion of copper piping and lead soldered joints has resulted in the necessity for early repair and/or replacement of copper piping systems (Hultberg and Wenblad, 1980).

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1) Determine the geographical location of natural resources and materials (streams, lakes, forest, crop lands, man-made structures, etc.) which are now being affected by acid deposition or may be affected in the future.

2) Determine the present and future costs of detrimental and possible beneficial effects on the resources that are affected.

3) Identify those resources society wishes to protect from detrimental effects.

4) Conduct a comparative analysis of various strategies by which the protection desired by society might be achieved. Alternative strategies would include the following:

   (a) decrease the amount of emissions leading to acid deposition;
   (b) use ameliorative treatments such as liming of watersheds or application of protective coatings to materials; or
   (c) develop acid-tolerant forms of life and structural materials.

5) Assuming that decreased emissions is the alternative of choice as suggested by the National Academy of Sciences in the U.S. (NAS, 1981) and the Ministry of Agriculture and Environment in Sweden (MAE, 1982), determine the amount by which acid deposition will need to be decreased in order to avoid undesired effects on the resources selected for protection, i.e., indentify "acceptable" target loadings.

6) Determine where and by how much emissions of what acid-deposition precursors ($(S)_x$, NO_x, HC, etc.) will have to be decreased in order to achieve the extent of decrease in deposition that will be required in the regions selected for protection.

7) Evaluate specific strategies and tactics by which each selected source region could do its part to achieve the total emissions decrease that is necessary. Possible methods would include the following:

(a) conserve fossil fuels;
(b) alter the mix of energy sources to include a higher proportion from non-polluting sources such as solar or possibly nuclear;
(c) alter the mix of industries to favor those with smaller emissions;
(d) use some combination of fuel switching, fuel cleaning, combustion modification, flue-gas treatment, etc.
(e) alter regulations to include existing as well as new sources, encourage "least emission dispatching," permit the purchase of "pollution rights," etc.

Prepared by Ellis Cowling, September 29, 1982

7. New Evidence on Acid Rain from Elemental Tracers

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During the last several years, a picture of air pollution in the Northeast has evolved which emphasizes its regional character. According to this view, sources and transport of aerosols and gases, especially those that are formed within the atmosphere from precursor gases (ozone, sulfate and nitrate are examples of these so-called "secondary" pollutants), are usually best understood on scales of tens to hundreds of miles rather than in terms of local sources. It is now widely accepted that the appropriate geographical unit for dealing with these constituents is groups of states rather than individual states or counties.

This amounts to a major change in control strategy. It is long overdue and is to be applauded. Studies which demonstrate long-range transport of air pollutants in various parts of the world are now abundant; there is no reason why pollutants in eastern North America should not also be carried over similarly long distances.

I have mixed feelings about these recent developments, however. On the one hand, the regional approach to air pollution is eminently reasonable. Many pollutants do indeed move easily over such distances. On the other hand, I am concerned that the pendulum may have swung too far toward regionality. We have gone from explaining nothing by distant sources to explaining everything by distant sources. The fact that a pollutant is transported from distant sources does not automatically mean that those distant sources account for all its abundance. When a polluted air mass moves (even for long distances) along a source-free path, the source of the final pollution is obvious. But when additional sources lie along the transport path, the role of any one of them becomes much less clear. Weaker but nearer sources may indeed overwhelm stronger but more distant sources. Although transport is present, its effects may be overridden by nearby sources.

The Northeast is a very complex area, and includes examples of both situations described above. The western Northeast contains areas such as upper New York State, which are remote, mountainous, and separated from strong source areas

such as the Midwest by several hundred miles. It is very likely that concentrated pollutants approaching the Adirondacks from the Midwest have travelled long distances to get there. Thus, it should come as no surprise that a long-range explanation has evolved for air pollution and deposition in the Adirondacks.

But the coastal Northeast, where most of the Northeast's people live, is different. It contains a continuous zone of emissions from at least Washington through Boston, the "Megalopolis" which gained fame some years ago. Within this region, the emission of SO_2 per unit area (the measure which determines its atmospheric concentrations) is fully one-half that of the six midwestern states often cited as the worst polluters. Because the northeastern states are so small, their total emissions do not look impressive in state-by-state lists. But putting them on an equal-area footing with the midwestern states creates quite a different impression. Thus, one should not expect pollutants within the crowded coastal strip to show as large effects of long-range transport as is seen in the remote western Northeast.

I feel that it is extremely important to recognize that there is no such thing as "the" Northeast, either geographically, demographically, or relative to air pollution. The Northeast is composed of at least two distinct subregions, and possibly more when its northern fringes are considered. And yet, it was (and still is) common to hear the Northeast discussed as an entity, with the results of scientific studies in one part being applied freely to another part.

One example of this is Whiteface Mountain, near Lake Placid in the heart of New York State's Adirondack region. A series of careful studies has shown that Whiteface Mountain receives the majority of its airborne sulfate in pulses from the southwest during summer (Parekh and Husain, 1982; for example). Trajectories of these air masses generally pass over or near the Ohio River Valley. Within these trajectories, the highest concentrations are associated with air masses which had previously stagnated near the Ohio River Valley, and then moved rapidly to Whiteface (Samson, 1980). Unfortunately, however, these results have often been presented as evidence for the importance of transport from the Midwest to "the Northeast," rather than from the Midwest to the western fringes of the Northeast. Excessive generalization such as

this has promoted a climate in which the long-range explanation is invoked before all others.

An extreme example may illustrate this point. In a 1976 study of the summer aerosol in and around New York City, sulfate concentrations were measured both in the city proper and at High Point, New Jersey, 55 miles to the west-northwest (Wolff et al., 1979). During August, sulfate was often surprisingly concentrated at High Point and averaged 86% of the New York City values on days when the wind blew from High Point toward New York City. On this basis, Wolff et al. concluded quite correctly that much of the city's sulfate was due to transport. But they were surprisingly quick to identify High Point's sulfate with the Midwest (Ohio, West Virginia, Kentucky, Illinois, Wisconsin) when there was at least 400 miles of Pennsylvania in between. Wolff et al. even implied that much of New York City's sulfate during that August was attributable to sources in the Midwest even though they had no measurements beyond High Point.

On the basis of these studies and others like them, an extremely strong picture has been created, in the minds of scientists and laymen alike, that sulfate in large portions of the Northeast comes from the Midwest where power plants burn high-sulfur coal. Even the forests of Maine are held by some to be influenced by acidity from the Midwest.

This is not merely an academic matter. The idea of an all-pervasive midwestern influence is imbedded in the current acid rain bills before both the House and Senate, which seek to control acid deposition by targeting the midwestern states for 40-60% reductions in SO_2 emissions while many northeastern states would cut back by only 10% or less.

In fairness, we have to admit that the evidence for long-range transport of sulfate from the Midwest is extremely attractive and convincing. There is little doubt that it occurs, and that it is indeed the correct explanation for acidity in certain parts of the Northeast. But when one admits that not all of the Northeast may have the same sources of air pollution, and brings new tools to the problem, one quickly comes to a radically different view of things.

This is what happened to us beginning in September 1981, barely a year ago. Until that time, we had no reason to doubt the long-range explanation and had accepted it totally (and uncritically). After all, even though sulfate

measurements and trajectory analysis have serious drawbacks, coupling them eliminates many of the weaknesses and allows an (apparently) comprehensive explanation to be formulated. At the same time, however, we wished to solidify this explanation by confirming it with detailed chemical measurements on the aerosol. Because of the very different elemental compositions of aerosol originating in the Midwest and Northeast (discussed below), we felt there was a good chance of sensing midwestern aerosol even in the middle of the Northeast. We expected that the most likely manifestation of midwestern aerosol in our part of the Northeast (Rhode Island) would be during sulfate episodes of summer. These episodes typically occur when air masses move from Midwest to Northeast on the backside (to the west and north) of a high-pressure area centered in the mid-Atlantic states, or somewhat later in the synoptic cycle, on the leading edge (to the south and east) of an advancing low-pressure area. (These same conditions, and more commonly the former of the two, bring midwestern aerosol episodically to upper New York State.) Of course, aerosol transported from the Midwest is certain to pick up some northeastern character by the time it has reached Rhode Island. Consequently, our criterion for sensing midwestern aerosol had to be relative rather than absolute: a composition systematically more midwestern during sulfate episodes than before or after them. We had no preconceptions about the degree of differences between episodes and nonepisodic periods that we might find.

Our tool for detecting midwestern aerosol was the ratio of the non-crustal component of manganese to the noncrustal component of vanadium in the aerosol, or the Mn/V ratio for short. Beginning in 1980, we had used this ratio to discriminate between aerosols of the northeastern United States and those of western Europe, both of which were candidates for explaining Arctic pollution aerosol. The Mn/V ratio on western Europe is consistently 1-2, whereas that of the northeastern United States is more like 0.2-0.4. Thus, a factor of five is available to discriminate between these two regions. (This was the first time that systematic differences in aerosol composition had been found for entire regions.) From earlier studies, we knew that the Mn/V ratio of the Midwest was even higher than that of western Europe, roughly 3-5 or so. Thus, an order of magnitude in Mn/V ratio was

unavailable to discriminate between the Northeast and Midwest.

In September 1981, the first set of aerosol data became available for testing our hypothesis of midwestern signatures during episodes in the Northeast. From 1977-80, we had collected 235 continuous semi-weekly filter samples of aerosol outside our laboratory in Narragansett, Rhode Island. These filters were analyzed for sulfate by colorimetry and for trace elements (including Mn and V) by neutron activation. Initially, only the sulfate data and one year of the trace-element data were available. These, however, were quite enough to reveal the unexpected facts that the aerosol throughout the year had an overwhelmingly northeastern signature, that there was no systematic shift to higher Mn/V ratios during sulfate episodes, and that there was no tendency for high sulfate to be associated with high Mn/V ratio at any time during that year (roughly calendar 1979). In short, aerosol during the strongest sulfate episodes in Rhode Island had just as northeastern a signature as did that outside episodes.

We didn't understand the full significance of these results then, nor do we now. But we sensed that they were important. At the urging of colleagues in the field of acid precipitation, which at that time was starved for any new data which could be brought to bear on the controversy surrounding sources of acidity in the Northeast, I summarized the sense of these results in a three-page statement dated 23 November 1981. The major message of this statement was that our new data revealed that northeastern aerosol was much more complex in origin than previously thought, and that local (northeastern) sources seemed to be important in addition to distant sources.

This statement soon sparked a great deal more controversy. In spite of the caveats interspersed throughout, it was endorsed by various midwestern interests as a finished study which proved once and for all the lack of long-range transport to the Northeast. (It was not and did not.) On the other hand, some northeastern groups, mostly environmental, went to the other extreme and attempted to discredit both the study and the concept that elements could be valuable tracers of sulfate aerosol. (They succeeded in neither.) Most scientists were considerably more cautious and preferred to withold judgement until the data and interpretations were published formally and could be examined carefully.

During late spring and summer 1982, after the storm of attention quieted a bit, we were able to finish our analysis of the entire suite of samples for trace elements for two summer and two winter periods by long-lived neutron activation and analyze the results statistically. A much more detailed view of the sources and transport in the Northeast has emerged, which supports and extends the original picture presented in the November 1981 statement. The entire set of raw data, together with their detailed interpretations, is presented in a University of Rhode Island Technical Report dated 1 October 1982 (Rahn et al., 1982). The following paragraphs highlight these new results.

Elemental concentrations in the two source areas of interest show clearly that most elements should not be suitable tracers of aerosol from either Midwest or Northeast because their concentrations in the two source areas are nearly equal. Se, Sb and Zn are examples of this kind of element. (For Se this came as something of a surprise, because it and As had often been proposed by others as tracers of coal combustion.) But tracer elements (those with significantly higher concentrations in one or the other region) can be found--noncrustal Mn and As for the Midwest and noncrustal V for the Northeast.

Our results for the Rhode Island aerosol confirmed these predictions. Noncrustal Mn and As do indeed show influences of the Midwest on occasion, but as temporary perturbations on a dominant northeastern aerosol. Noncrustal V seems to be nearly exclusively northeastern in origin. Neither Se, Sb or Zn seems to have a clear component from the Midwest.

Transport of aerosol to Rhode Island, as deduced from variations in Mn/V ratio greater than those shown by individual source areas, is seen in both summer and winter and on both the short- and the long-term. Long-term differences in composition, which are always small enough to be attributable to differences in transport within the Northeast or from greater distances, occur in both summer and winter, but short-term pulses from the Midwest are seen only in winter and in only 3% of the samples.

The long-term effects of transport on sulfate in Rhode Island are always modest and are opposite from summer to winter. From one winter to the next, higher Mn/V ratios bring increases in sulfate (consistent with a greater midwestern influence), but from one summer to the next, increases in Mn/V

ratio bring decreases in sulfate (consistent with local sources).

To date, we have found six cases of high enough Mn/V ratios in individual samples to indicate that they were episodes of transport from the Midwest. Interestingly, all six occurred during winter, five of these six came in a single winter (1977-78), and four of these five came during a single five-week period. Thus, temporal differences in transport from the Midwest exist with periods of weeks and months. During these winter episodes, strong increases of the Mn/V ratio (by 4.7X) brought only modest increases in sulfate (57%). Thus, the influences of the Midwest on sulfate aerosol in Rhode Island seems to be modest no matter what the season or the time scale.

But sulfate undergoes great increases in concentration during summer which cannot be linked to any of the elemental tracers we have yet found. Its mean concentrations are three times higher than its mean winter concentrations, and its concentrations during summer episodes are another factor or two higher. Our elemental tracers show that sulfate episodes are exactly that--episodes of sulfate only. Because our elemental tracers can sense transport when it is present during winter, we must conclude that there is no enhanced transport either during summer as a whole or during sulfate episodes of summer.

If sulfate of summer and episodes are not attributable to enhanced transport, what is it from? The only other explanation is enhanced production, or oxidation, from SO_2. This is reasonable on several grounds. Throughout the Northeast, opposite seasonalities of SO_2 and sulfate are observed, with summer being the time of minimum SO_2 and maximum sulfate and winter the reverse. This implies that oxidation is faster in summer than in winter. Furthermore, our measurements reveal that the periods of highest sulfate are just those when Rhode Island is in tropical air masses, whose abundant sunshine, heat and water vapor provide conditions ideal for oxidizing SO_2 to sulfate.

In summary, then, winter is the season of transport to Rhode Island and summer is the time of transformation. The question then becomes what the origin is of the SO_2 being oxidized in summer. For this one must look beyond our studies. It seems more and more clear that the range of SO_2 may be less than 200 miles in summer (Georgii, 1978; Pierson et al., 1980: Perhac et al., 1981). If

this is correct, then the sulfate and acidity over much of the coastal Northeast during summer comes from northeastern presursors, and will not be reduced significantly by legislation aimed at the Midwest.

On the other hand, it should be pointed out that recent research, most of which is still unpublished, is suggesting that the dominant source of acidity in rain is from oxidation of SO_2 in cloud droplets, not incorporation of pre-existing sulfate aerosol. If this is correct, then the range of influence of source regions may be a complex function of factors not considered here, such as concentrations of oxidants. In short, our results for aerosol may not apply to rain. In the near future, we intend to check this by applying our elemental tracer technique to rain in Rhode Island.

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8. Understanding Acid Rain

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In this paper I address the question of the extent of our scientific understanding of acid deposition. Particular attention will be directed to recent scientific evidence on the relationship between pollutant emissions and acid deposition. Both my own research, and the research of others, has led me to conclude that reductions in sulfur emissions will lead to nearly comparable reductions in acidic sulfur deposition over the eastern United States. I further conclude that long-range transport of sulfur pollutants over many hundreds of miles is a major source of acid deposition over parts of the Northeast.

Here is an outline of the state of scientific understanding of acid deposition.

(1) Precipitation over most of the eastern United States, including the Southeast, is abnormally acidic, ranging up to 20 to 40 times more acidic than normal on an annual average basis in parts of the Northeast.[1] [2] Acid rain also has appeared in the Rockies[3] and is widespread in California.[4] Rainfall in the East is primarily a dilute solution of sulfuric acid while in the West it may be primarily either nitric acid or sulfuric acid.[1] [3] [4] [5] There is no question that precipitation acidity substantially exceeds the natural background value.

(2) Atmospheric loading of sulfur and nitrogen compounds is by far the major source of acid rain. In eastern North America, atmospheric loading of sulfur and nitrogen due to human industrial and transportation activity far exceeds that from natural sources. Natural sources of sulfur in the eastern U.S., much less than one million tons per year, are far too small to account for the sulfur, mostly in sulfuric acid, actually observed in precipitation, about two million tons per year. For comparison, man-made sources of sulfur amount to over 11 million tons per year[6] [7] [8] (equivalent to 22 million tons of SO_2). Approximately two-thirds of the total U.S. sulfur loading is from power plants, which also provide nearly 30% of the atmospheric loadings of oxides of nitrogen (NO_x). Emissions from the transportation sector are another major source of oxides of nitrogen, providing over 40% of the national total.[9] Since, on average, nearly three-fourths of the acid in eastern U.S. precipitation is due to sulfuric acid,[1] and since utilities are responsible for more than 70% of eastern U.S. sulfur emissions,[7] [8] it is certain that utilities are the major source of acid rain in the East. The recently issued report of the National Academy of Sciences confirms this conclusion.

(3) The detailed mechanisms for the transformation of sulfur dioxide (SO_2) and NO_x emissions into acid rain are not completely understood, but there is absolutely no doubt that the transformation occurs. I have spent most of the past year researching this transformation. A general description of the process is the following: SO_2 and NO_x emissions from various sources are mixed into the lower atmosphere with moisture and other pollutants. Out of this chemical soup, various nitrates and sulfates are produced, among them nitric acid and sulfuric acid. Some of this material is periodically rained out in precipitation and some remains suspended as fine particles. Many of these fine particles as well as untransformed sulfur dioxide molecules are eventually deposited as dry acid material in a process called dry deposition. In many areas, dry deposition is a major sulfur deposition mechanism. Thus, the acid rain, dry deposition and fine particle problems are intimately related.

Let us examine the transformation process more closely. There are essentially three pathways to the formation of sulfuric acid in the atmosphere: oxidation of sulfur dioxide in the ambient gas, in cloud and rain droplets, or on particle surfaces. With the exception of the near-source region, particle surface reactions appear to be an insignificant contributor.[10] However, substantial evidence has accumulated that nearly all SO_2 processed through rainstorms is converted to sulfates, and that this process is the major source of precipitation sulfuric acid.[11 12 13 14] My own research[14] demonstrates that for this portion of the sulfuric acid produced, the relationship of average airborne concentrations of SO_2 to annual average sulfuric acid in precipitation is nearly one-to-one. I estimated that a 50 percent emissions reduction will produce more than a 45 percent reduction in precipitation sulfuric acid produced by this route over the year in the eastern United States.

The other pathway to sulfuric acid production is the gas phase-oxidation of sulfur dioxide in plumes and in the ambient air. It has been demonstrated that the levels of sulfuric acid produced by this pathway also respond nearly linearly to SO_2 concentration changes,[15 16] holding oxidant levels and meteorology constant.

I conclude, therefore, that the relationship between sulfur emissions and levels of sulfuric acid in precipitation is, indeed, very close to one-to-one for substantial emissions reductions no matter which pathway is dominant. There is no evidence of any significant oxidant limitation effect on sulfuric acid formation on a regional and annual basis. Furthermore, since dry depositation of SO_2 appears to operate in a linear fashion on a regional average basis,[17] it is clear that total acidic sulfur deposition

will vary nearly linearly with sulfur emissions on a regional average basis.

The SO_2 and NO_x which are not converted into acids in the atmosphere and deposited in rain fall are still a source of environmental damage. Un converted SO_2 is eventually deposited on land, water, plants, and trees and much of this material is then converted to acid. Suspended fine particles present a health hazard when inhaled by humans. Much of the fine particulate matter is eventually deposited on leaves, soil, and surface water and, along with the dry sulfur dioxide, contributes perhaps an additional 30% to ecosystem acidification. Thus, almost all of the SO_2 originally emitted ends up on the earth's surface in one harmful form or another. In addition to a decrease in the acidity of precipitation, therefore, a decrease in SO_2 emissions will reduce environmental damage caused by dry deposition. The reduction in dry deposition of SO_2 emissions will reduce environmental damage caused by dry deposition. The reduction in dry deposition of SO_2 appears to occur in direct proportion to the reduction in sulfur dioxide emissions.

(4) Long-range transport plays a vital role in the distribution of acid rain, sulfur dioxide, and fine particles about the country. Recent atmospheric modeling summarized in the report of the Working Group on Atmospheric Modeling Under the U.S.-Canada Memorandum of Intent on Trans-Boundary Air Pollution[19] and the Second Report of the U.S.-Canada Research Consultation Group on the Long-Range Transport of Air Pollutants [20] provides a general picture of this process. There is little doubt that most of the wet deposited sulfur including sulfuric acid reaching the Adirondacks, for instance, originates outside the Mid-Atlantic region, largely in the Ohio River Basin and the Upper Midwest. The contribution of U.S. sources to sulfur deposition in Canada is equal to the contribution of Canadian sources to sulfur deposition in Canada. Furthermore, the U.S. contributes five times more to deposition in Canada than Canada does to deposition in the U.S.[20]

My own research also throws some light onto this question. About 22 percent of sulfur emitted in the eastern U.S. is detected in rainfall in eastern North America. Because rainfall is rather infrequent, the survival time for sulfur dioxide in the atmosphere must be very long, or much less sulfur would last long enough to appear in rainfall. This survival time is, in fact, long enough that prevailing winds must carry a substantial fraction of the sulfur for distances of 500-1000 miles before it is deposited.[16]

Further evidence of the significance of long-range transport comes from satellite photographs of pollution episodes combined with simultaneous ambient air measurements.[23] These measurements show the large scale relation-

ship of sulfates, ozone, TSP, and reduced visibility over the East. Trajectory analysis also has demonstrated that specific instances of atmospheric stagnation in the Midwest are correlated with enhanced sulfate levels at later times in the East.[24] Research performed in conjunction with the SURE studies has confirmed the existence of long-range transport of sulfates.[25] The reality and significance of long-range transport is no longer in doubt.

(5) Historical data on precipitation acidity over the last 20-30 years is not of high quality. However, these data do suggest a relationship between increased utility emissions through taller stacks to the South and West and the spreading out of the region of abnormally acidic rainfall. Precipitation pH data from the 1950's, even when corrected for the possible neutralizing effects of drought-generated dust, indicate a spreading of the region affected by acid precipitation,[26] in spite of the fact that total U.S. sulfur emissions have not changed much. However, the fraction of emissions generated by utilities to the South and West commonly emitting through tall stacks has increased markedly in the last several decades.[9] Furthermore, the few measurements made in the 1930's indicate that rainfall in the Northeast was much less acidic at that time.[27] A glance at a map of precipitation acidity in the U.S. clearly shows the intimate association of fossil fuel emission sources and abnormally acidic precipitation.[1 28] Most significantly recent studies[29 30] indicate that the decrease of sulfur emissions in the Northeast over the last decade has in fact been accompanied by a decrease in sulfate deposition levels, a fact which should lead us to anticipate the success of an emissions reduction strategy.

(6) Arguments have been made that low rainfall pH measurements at a few remote island stations[31] mean that rainfall is normally very acidic. I would like to emphasize the complete irrelevance of this argument to the eastern U.S. where man-made sources of acidity far outweigh natural sources. Furthermore, some natural sources of sulfur are more significant for these island stations than for the U.S. mainland. Finally, these observations may simply indicate the importance of global transport of pollutants at certain locations since some remote stations report normal pH levels of 5.6[31] or the lack of natural buffering in the atmosphere at these stations.

In summary, it is certain that precipitation in the U.S. is now far more acidic than it would be in the absence of human activity. The primary source of this acidification, especially in the eastern U.S., is utility emissions, mainly of sulfur dioxide. There is now strong evidence that substantial reductions in utility sulfur dioxide emissions will lead to comparable reductions in wet sulfur deposition, precipitation acidity, suspended sulfates and total sulfur deposition. It is certain that the problems

associated with sulfur deposition in its various forms cannot be alleviated without reductions of utility SO_2 emissions. However, mobile sources continue to be a significant component of this problem, and their relative importance will increase as utility emissions are reduced.

The effect of acid rain have been documented amply. These include the destruction of aquatic plant and animal populations, alteration or destruction of non-aquatic eco-aquatic ecosystems, toxification of drinking water, damage to forest ecosystems and costly damage to materials.

My conclusion, as a scientist, is that the damage caused by acid rain indicates a widespread attack on the environment, and that we have enough knowledge about the sources of acid rain to initiate a long-term control program aimed at the abatement of emissions of sulfur dioxide and oxides of nitrogen. Since utility sulfur dioxide emissions are the major single source of the precursors of acid rain, and since sulfur oxides appear to pose a greater threat to the environment than other components of acid deposition,[32] these emissions are the logical initial target of any control strategy.

Finally, let me remark on the proposed acid rain control strategies. Legislation approved recently by a Senate Committee shares the sulfur dioxide reduction responsibility among the eastern states by giving the largest reduction responsibility to the largest emitters. Some observers have argued that the New York-New England area should shoulder a greater share of the burden, because local sources may be important to acid deposition.

There are several logical underpinnings to any control strategy, including physical effectiveness, economic equity, and cost effectiveness. The proposed strategy generally meets these tests. With regard to physical effectiveness, no current model attributes less than 40 percent of the sulfur deposition in the Adirondacks to the states emitting over one million tons of SO_2. Some models attribute two-thirds of the sulfur deposition to those states. Therefore, the desired 50 percent reduction of sulfur deposition may not be attainable without large reductions in those states. Secondly, many of those states have relatively low electricity rates compared to eastern states, partly due to the use of high sulfur fuels. Finally, some reductions can be obtained most cheaply in those states due to the low marginal cost of emission control.

The large emitting states along the Ohio River affect many sensitive areas aside from the Adirondacks, such as the Great Smokies. Emissions reductions in those states also would improve the environment in the Ohio Basin itself. Emissions reductions in the Northeast, however, tend to affect only the Northeast. Of course, emissions reductions local to sensitive areas are particularly

effective in diminishing deposition in those areas, so the proposed requirement of a 160,000 ton reduction in New York is, if anything, too small. However, the idea that emissions reductions in New York-New England alone can solve a national problem, or even the Adirondacks problem, is patently false.

Research on acid rain should continue, but the time for legislative action on controls has certainly arrived.

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9. A Potential Constraint on Illinois Coal

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The acid rain issue is a potential constraint on Illinois coal. In fact, it's a potential constraint on energy resource development throughout the Midwest. Acid rain is, of course, an environmental issue. It is also an important economic issue. Any public policy response to acid rain will have to consider both sides carefully.

One remarkable aspect of the acid rain issue is that public concern developed over a period of just a few months. Another remarkable aspect, and one I find most encouraging, is that the rate of new scientific studies and findings is accelerating. Although there are still more questions than answers, the amount of data now available is many times more than what was reported only two years ago.

When concern for acid rain developed, speculation about its causes, effects, and cures went far beyond proven fact, and some of these earlier ideas are still with us. It was believed that rainfall in the Northeastern U.S. was becoming more acidic. Sulfates were an important component in this acid rain. Large sources in the Ohio Valley were heavy emitters of sulfur oxides, and prevailing winds blew from west-to-east. So it was really quite simple: We could solve the acid rain problem in the Northeast by placing additional emmissions controls on utilities in the Midwest.

Current scientific data on the acid rain phenomenon casts strong doubt on these earlier ideas. First, long-term rainfall data from the Northeast, such as the USGS in New York State and Hubbard Brook, do not show a trend toward greater acidity. If they show anything at all, it is that little has changed over the past 15 years.

Whether certain lakes and streams have become acidic in recent years is also open to some question. Detailed historical analyses of some adirondack lakes indicate that many have been acidic for many decades. Factors other than acidity may be important in some observed loss of fish populations. This is not to say that acid rain is not a serious ecological concern. It is. However, it doesn't seem to be a crisis that demands immediate action.

The subject of long-range transport has engaged many researchers over the past few years. That

subject is highly complex, and we are a long way from understanding the chemical interactions and weather patterns that produce and transport acid rain components.

There has been considerable pressure on Congress to do something right now about acid rain, and one comprehensive piece of legislation has already emerged from a Senate committee. This amendment to the Clean Air Act, called the Mitchell Amendment, deserves serious study. If this measure or something like it is passed into law, it will have a grave impact on economic development in the Midwest. Further, it might do little to help the acid rain problem.

Briefly, this bill would require a large-scale reduction in SO_2 emissions in a 31-state area comprising the eastern half of the U.S. These reductions would apply to older electric plants, mostly coal-fired. The greatest reductions would come from the Midwestern states.

If one were to go looking for precursors to acid rain in the Northeast, one wouldn't have to look as far away as Ohio or Illinois. In terms of land area, and considering emissions from all sources, the Northeastern U.S. is second only to the Midwest in emissions density. Admittedly, it is hard to control emissions from small stationary and mobile sources. However, if acid rain proves to be mostly a local phenomenon, legislation such as the Mitchell Amendment may be a costly mistake. Substantial increases in power generation in the Midwest, together with employment displacements in the coal mining industry, could cause irreparable harm to the economically frail American industrial belt.

A realistic look at the public policy aspect of acid rain must be made. Someday technology will provide us with solutions to the acid rain problem that are not economically crippling. The problem that faces us now is communicating a balanced view of the acid rain issue to our leaders and to the American people.

10. A UMWA Perspective on Illinois Mining

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Nationwide, the UMWA represents over 250,000 working, retired, and unemployed coal miners throughout the United States and Canada. While our membership is heaviest in coal mining communities east of the Mississippi River, we represent underground and surface miners throughout the western states, with members in Arizona, New Mexico, North Dakota, Colorado, Wyoming, Montana, and Utah. In Illinois, according to an analysis of the 1981 production and employment figures provided by the Illinois Department of Mines and Minerals, over 97% of the coal produced in this State was mined by UMWA members. We represent, through our collective bargaining agreements, over 22,000 working, retired, and unemployed Illinois men and women.

Our International Union and District 12 memberships have a strong interest in the current Congressional reauthorization of the Clean Air Act, both as workers and citizens. As the nation's largest energy-producing labor union, we are concerned that our pollution control strategy recognizes the need for balanced energy development; the jobs of thousands of our members and the economies of the communities in which they live are affected by environmental decisions. As citizens of both Canada (where we represent thousands of miners in Nova Scotia, Alberta, and British Columbia) and the United States, we are concerned that business interests not override the clearly established need for clean and healthful air.

The current Congressional reauthorization of the Clean Air Act will have a significant impact on coal production and demand in areas with high sulfur coal, such as Illinois. The two principle issues affecting the use of high sulfur coal involved in the current reauthorization are attempts to amend the existing law to require significant reduction in sulfur dioxide emissions from existing power plants--the acid rain issue--and considerations of amending out of the Act or weakening the current requirements of section 111--the percentage reduction requirement. This paper addresses the economic and employment impacts of these two possible actions on coal miner employment throughout the United States, and particularly in Illinois, as well as the impact of those suggestions

on the local and regional economies in the high sulfur coal producing states.

In July, 1982, the Senate Committee on Environment and Public Works passed an amendment that would require an eight million ton annual reduction in sulfur dioxide emissions by 1995. The emissions reduction would be measured from the then-current level of sulfur dioxide emissions which are projected to increase slightly over the next twelve years. This amendment was a modest variation of the requirements contained in S. 1706, a comprehensive acid rain reduction bill co-sponsored by six members of the Senate Committee. S. 1706 was designed to reduce the effects of acid deposition by requiring a significant reduction in sulfur dioxide in the states along and east of the Mississippi River. At the time it was prepared in 1981, the bill called for an annual reduction of 10 million tons of sulfur dioxide over a ten year period ending in 1992.

The UMWA has reviewed S. 1706 and, in so doing, measured the impacts of the projected production losses on jobs in the affected states. We have also measured, in dollar terms, the effect of S. 1706 on the economy of twelve coal-producing states within the region that is jurisdictional under both that bill and the amendment passed by the Senate Committee.

The results of our study reveal the following effects of S. 1706 on coal mining jobs and the overall economy:

- over 89,000 coal mining industry employees would lose their jobs if the acid rain program were fully implemented;
- the economic loss to the eastern and midwestern coal producing states, as a result of the loss of these coal mining industry jobs alone would be $2.29 billion;
- the "ripple" effect in non-mining sectors of the economy would result in a loss of an additional $3.4 billion;
- the coal mining and related losses in the twelve-state region combine to a total of nearly $6.63 billion under S. 1706; and
- coal mining industry employee job losses in Illinois would be greater than 15,500 jobs lost, accounting for $398 million in annual coal mining industry employee economic losses and $896 million in total annual indirect economic losses.

In this study, the UMWA adopted the projected coal production losses the Peabody Coal Company estimated would occur if S. 1706 became law. The

Peabody study assumed that utilities would switch to low sulfur coal rather than retrofit any of their existing power plants with scrubbers, in order to meet the emission reduction required under the bill. Given the fuel adjustment clause "pass-through" provisions in Illinois and the capital formation problems facing the electric utility industry, this presumption seems to be a realistic expectation of how utilities would respond to an acid rain mitigation plan. Even assuming, however, that 25% and 50% of the projected loss of high sulfur coal would not occur--instead of fuel switching, scrubbers would be installed at some existing plants--the economic impact throughout the coal producing states along and east of the Mississippi River under S. 1706 would still be significant, totaling $4.97 billion and $3.32 billion respectively. In Illinois, assuming that 25% and 50% of the projected loss of high sulfur coal production would not occur, our Illinois coal mining industry employee job losses would still be 11,650 and 7,770 jobs respectively, with total annual economic losses computing to $971 million and $647 million respectively.

It is interesting and important to note that in the context of the continuing Congressional analyses on jobs and economic losses resulting from implementation of any of the proposed acid rain control strategies, the Congressional Office of Technology Assessment has accepted the UMWA's job loss analysis methodology. This is not to say that the production loss computations which the Peabody Coal company has produced, and upon which the UMWA's job loss and economic displacement totals are based, has been accepted by OTA. At the same time, however, it is important to note that the principal power plants which use Illinois coal in the State of Illinois--the Illinois Power Baldwin Plant, the Commonwealth Edison Kincaid facility, the Central Illinois Public Service Company Coffeen Power Plant, and the Electric Energy, Inc. Joppa facility, which, on a combined basis, use approximately 13 million tons of Illinois coal annually--are among the most significant emitters of sulfur dioxide in the state and would be the target plants affected by the Senate amendment passed in July, 1982.

These potential job and economic losses would affect dramatically an Illinois coal industry which is already suffering from significant unemployment and shortened work weeks. In Illinois currently, there are at least 3,300 UMWA members laid off. This constitutes better than 20% of the 1981 Department of Mines and Minerals total for coal industry employees.

As you might expect, the UMWA has argued strenuously in opposition to the Senate Committee on Environment and Public Works' Amendment and against S. 1706, the basis for that amendment during the ongoing Congressional reauthorization of the Federal Clean Air Act.

The second principal concern which Illinois UMWA members have in the current Congressional reauthorization is whether or not the current effort to eliminate or significantly weaken the percentage reduction requirement of the new source performance standards will be successful. We believe that retention of Section 111 of the Clean Air Act will reduce sulfur dioxide in the future, will permit the development of all our nation's coal resources, and will minimize the adverse economic and employment impact that sometimes accompanies pollution abatement strategies. We have urged subcommittees and committees of both chambers of the Congress to oppose efforts to eliminate or weaken the percentage reduction requirement. Thus far, on this issue, we have been successful.

Coal is absolutely necessary for the Nation's and Illinois' economic growth. At the same time, the UMWA is the first to acknowledge that its use represents one of the greatest challenges in the pursuit of clean air. We maintain that the environmental problems related to the use of coal, however, are not insoluble. Significant advances have been made in pollution control technologies in the past decade. We feel strongly that the use of technologies such as flue gas desulfurization, despite protestations to the contrary, are proving efficient on high sulfur coal wherever such systems have been installed. According to the United States Environmental Protection Agency, flue gas desulfurization systems for high sulfur coal have increased their median availability by better than 50% between 1978 and 1980. The operating experience and actual removal efficiencies of these units have increased significantly since 1974. For example, at the Central Illinois Public Service Company's Newton station, a 575 megawatt plant that uses high sulfur Illinois coal, scrubber availabilities were 99%, 100%, and 90% respectively for the first three months of 1981. For the six-year period between 1974 and 1980, the average capacity of the FGD-equipped power plants increased from an average of 170 megawatts to 340 megawatts. The improvement in the system, as I understand it, continues through the reporting periods of 1981 and early 1982.

The variation in sulfur content of coal is an important consideration for electric utilities in Illinois. As examination of our experience in this

state over the past several years clearly demonstrates, traditional markets can be displaced as a result of fuel choice decisions made by utilities in response to the Clean Air Act. In 1973, nearly 73% of the coal burned by Illinois utilities was produced in Illinois coal mines. In response to the Clean Air Act and its intended regulations, however, utilities began seeking low sulfur "compliance" coal from western states. By 1980 the consumption of Illinois coal by Illinois utilities dropped to 50.6% while during the same time period the use of Wyoming coal by Illinois utilities rose from 4.3% to almost 30%. In other terms, Illinois burned 4.7 million annual tons less of its own coal and 9.2 million annual tons more Wyoming coal during this eight-year period. This occurred despite the long distance between the producing coal fields and the consuming utilities and the resulting high transportation charges that are immediately passed through to consumers by virtue of the operation of the Illinois fuel adjustment clause. Utilities have chosen this compliance coal option rather than install pollution control technology, the latter alternative allowing them to continue locally available coal. The principal reason for this choice, I would estimate, is that pollution control devices represent a capital expenditure for which the utility must request a rate increase from the Illinois Commerce Commission to recover that expense.

An examination of other midwestern states shows a similar penetration of traditional high sulfur coal markets by "compliance" coal from outside the region.

These market losses have resulted in substantial unemployment for coal miners in those traditional coal producing states. There are currently more than 15,000 skilled UMWA coal miners out of work in Ohio, Indiana, Illinois, western Kentucky, and northern West Virginia. We have long held the belief that job displacement and economic disruption can be minimized if the Congress adopts coordinated energy and environmental policy that encourage regional production and marketing of all this Nation's coal resources.

The Clean Air Act of 1970 required that all new stationary sources of pollution meet a federal emissions standard to be determined by the USEPA Administrator. In the Clean Air Act amendments of 1977, Congress not only retained the requirement of a fixed emissions standard, but added the requirement that such new sources achieve a percentage reduction of emissions from uncontrolled levels.

In September, 1978, USEPA proposed a uniform percentage reduction standard of 85% for all new coal fired power plants. When the final rule was promulgated in June, 1979, a variable percentage reduction

was adopted, ranging from 90% for high sulfur coal to 70% for low sulfur coal. It is this requirement, which has withstood challenge at the federal appellate court level, which is currently being viewed by many as an appropriate place for amending the Clean Air Act. In my opinion, the current statutory and regulatory scheme serves to implement Congressional goals declared in both 1970 and 1977. Those goals were intended to:

- fully develop all energy resources, including high sulfur coal throughout the United States;
- achieve the maximum practicable emissions reduction by relying on the use of locally and regionally available energy resources, thereby maximizing the potential for long-term growth;
- avoid placing certain states or groups of states in a competitive disadvantaged position with respect to attracting position;
- encourage improvement in technology for all new sources; and
- produce employment benefits.

The percentage reduction requirement operates to accomplish these objectives. First, under the existing statutory and regulatory framework for new source performance standards, new plants will produce 3.3 million fewer tons of sulfur dioxide in 1995 than they would if the percentage reduction requirement were eliminated or weakened. Gains in reducing emissions will be realized as new plants come into service and older plants are retired. West of the Mississippi River, for example, current law provides for 35% fewer emissions than would have occurred under the standard allowed prior to the 1977 amendment. According to the USEPA studies of alternative NSPS strategies prepared during consideration of NSPS in 1979, the current standard would reduce annual emissions for all plants in 1995 (including older plants not covered by the new rule) by nearly 15%. Annual emissions by the year 2010 would decrease dramatically, according to an October 1981 study conducted by ICF, Inc., the same consulting firm used by USEPA. The new study, performed on behalf of the Peabody Coal Company, projects that sulfur dioxide emissions under the current NSPS would fall 54% nationally, from 21.3 million tons in 1990 to 9.8 million tons in 2010. Of that 11.5 million tons decrease, 8.2 million tons would come from the Northeast and North Central regions of the United States, the areas where acid rain legislation is intended to have an impact. In this context, retention of Section 111 tends to correct the acid rain problem.

Second, the law and its regulations allow for full development of all our Nation's energy resources, including medium and high sulfur coal from the East and Midwest. Analyses were conducted for the USEPA and the United States Department of Energy in 1978 and 1979 as well as for the Peabody Coal Company. These reveal that the current NSPS would increase coal production in the East and Midwest by at least 20 million tons in 1995 and up to 116 million tons in the year 2000 over what would be obtained without the current standard. If the statutory section on percentage reduction were eliminated, these projected gains would be lost and would accompany already devastating production losses. The Peabody Coal Company has estimated that, between 1977 and 1980, approximately 43 million tons of coal production has been displaced in the States of Illinois, Indiana, Pennsylvania, Ohio, Maryland, Tennessee, Missouri, Kansas, Oklahoma, and parts of West Virginia and Kentucky.

This coal production displacement accounts for much of the current coal miner unemployment referred to earlier.

These existing job losses would be greatly exacerbated by eliminating or weakening the percentage reduction requirement. The UMWA has analysed the impact that elimination of the current law would have on future incremental coal miner employment. In Ohio, Indiana, western Kentucky, and Illinois there would be over 13,300 incremental direct coal mining industry employee job losses in 1995; the ripple effect for direct job losses would total 25,764, and the total economic losses would be $893 million.

The projected incremental direct and indirect job losses for 2000 are based on the October 1981 Peabody study, which indicated that 83.4 million annual incremental tons of low sulfur coal would be shipped east if the current NSPS were eliminated and the 1.2 lb/MBtu pre-1977 standard reinstituted. This projection yields a direct coal mining industry employee job loss of better than 21,800 positions, indirect job losses of 42,133, and overall economic losses of $1.460 billion.

Elimination of the percentage reduction requirement, then, would reverse the goals previously embraced by the Congress: Increased employment and national development of all coal reserves. The statistics cited above dramatically illustrate the serious impacts of deletion of this requirement.

Third, the Congressional purpose of utilizing local and regional energy resources also would be undercut significantly by elimination of the

percentage reduction rule. Almost 40 million tons of low sulfur coal were delivered to utilities in Illinois, Indiana, and Ohio in 1980. Most of this coal came from such distant western states as Colorado, Montana, and Wyoming--at great transportation expense to consumers. This is destructive to the goal of coal marketing on a regional basis. Again, according to analysis performed in 1978 and 1979 for EPA and DOE, eliminations of the percentage reduction requirements would increase that coal displacement in all eastern states to 122 million annual tons in 1995. This threefold increase in the amount of western coal shipped east would further restrict the market of eastern and midwestern coal producers. This would dramatically curtail the use of this abundant high sulfur coal resource.

Fourth, the clear and unequivocal view of Congress since 1969 has been that the Clean Air Act should operate to force the development of pollution removal technology to achieve long-term emissions reductions and economic growth through all areas of the United States. FGD systems for low sulfur coals will never develop to their full capacity if the standard is eliminated or weakened. Much progress has been achieved over the past ten years in the removal efficiencies of all forms of FGD systems. The Congressional mandate is therefore being achieved. Elimination or weakening would abrogate Congress' long held view that the new source performance standards are intended to drive the development of technology.

Supports of the elimination of the percentage reduction requirement argue that high sulfur coal resources would not suffer under their proposal. The position of the Illinois Coal Association, the Indiana Coal Council, the Ohio Mining and Reclamation Association, and the Western Kentucky Coal Operators Association to retain the current Section 111 demonstrates the high sulfur coal industry's opinion that elimination of the rule would be unfair and retard future growth.

In conclusion, I sincerely believe that the future economic well-being of the Illinois coal industry depends on the outcome of the Congressional reauthorization of the Clean Air Act. Without clear Congressional intent to encourage all coals, it is likely that the next decade will be one of increasing regional energy warfare, with the West pitted against the East in a battle for jobs. Fortunately, this need not occur.

11. Marketing and Transporting Illinois Basin Coal

Gregg F. Haug
Marketing Analyst
Illinois Central Gulf Railroad

Illinois Central Gulf Railroad thinks Illinois Basin coal has a definite role as a United States export commodity. I'd like to address this topic because I think the export business is a growth opportunity for Illinois Basin coal.

ICG serves southern Illinois, southern Indiana, and western Kentucky, which is the area known as the Illinois Basin. Coal represents over 25% of our annual tonnage.

Illinois Central Gulf, unlike many transportation companies, owns neither coal mines nor reserves. The focus of our export coal activity has been and continues to be the land transportation link between mine-mouth and ship-berth. The viability of this link depends upon the export potential of Illinois Basin coal.

Any evaluation of this potential must be viewed from the importer's perspective. The ICG has expended a great deal of time, money, and human resources in evaluating the needs and concerns of potential importers.

It might seem unusual for a railroad to carry out a market survey in Greece, or coordinate a foreign trade mission to Barcelona, but that's just what ICG has done. Expanding the market for Illinois Basin coal is important to the railroad industry because the railroads carry the coal to the coast for export. Railroads are as dependent on coal for their livelihoods as the miners in southern Illinois.

There is a common belief that Illinois Basin coal will not satisfy European coal buyers' specifications. To determine the accuracy of the belief, ICG analyzed a number of well-known studies, such as MIT's World Coal Study. ICG also conducted its own study of the Basin, its coals, and international opportunities for these coals.

Some of the Illinois Basin coal that we transport is higher in sulfur content than is generally acceptable for some applications under current U.S. Federal regulations. But high sulfur content is not necessarily a major deterrent in dealing with the European Market. In Europe, existing and pending regulations vary by country, by region, and by industry.

The term "high sulfur" also needs closer examination. High, compared to what? We could go on at

great length discussing the merits of one nation's or one regions's steam coal properties. That is not the critical issue. What is important are the international market specifications. Sulfur content is only one of several key specifications. The important point is that there are European markets that Illinois Basin coal can readily satisfy.

ICG is continuing to fine-tune its focus on Europe by commissioning in-depth market studies on a country-by-country basis. We began with Spain. The results of the study indicate that Illinois Basin coals are both usable and acceptable, sulfur notwithstanding. This is particularly true in the Spanish cement industry, where up to two-and-one-half percent sulfur is readily acceptable.

Last summer ICG made the first shipment on a 125,000-ton contract for Illinois coal to be used by the Spanish cement industry. This was a breakthrough not only for rail transportation as a long-haul carrier of coal to New Orleans, but for southern Illinois coal producers. The Spanish study pinpointed:

- Specific utilities and cement plants -- both existing and planned;
- Port facilities;
- Coal import and demand projections;
- Coal procurement procedures; and
- The National Energy Plan of Spain.

Similar studies of the Italian and Greek markets have been completed. The cost competitiveness of Illinois Basin coals in the international marketplace has been widely debated. ICG examined this subject very carefully, since it wants to be one of the transport links between Illinois and Europe. As responsible businessmen, potential importers look at total coal costs -- the cost of "landed BTUs." Thus, we viewed Illinois Basin coals from a similar perspective, using the Port of New Orleans as the exit port.

Preliminary information on prospective European importing countries has yet to reveal a weakness in Illinois Basin coals regarding its costs of distribution. However, there is a problem that must be solved before the Illinois Basin exports begin. This is the problem of awareness.

In conducting studies of the European markets, ICG found that only Appalachian coal is thought of when U.S. coal is mentioned. Europeans see the eastern United States as a coal supplier, but see little beyond eastern Kentucky. Unfortunately, this

myopia extends even to the Federal Railroad Administration. For the most part, the FRA ignored Illinois Basin coal export in its projections of "Railroad Freight Traffic Flows -- 1990."

The most pressing need that must be met before Illinois Basin coal exports become a reality, is a massive effort to educate and inform. This effort must be coordinated among railroad, coal companies, and ports.

For its part, the ICG has and will continue to act as a catalyst for bringing together potential importers and coal producers by:

- Speaking out in behalf of the Illinois Basin as opportunities arise,
- Providing information materials,
- Working with ports and coal producers to develop transport ..on price packages attractive to potential importers,
- Conducting an advertising and publicity campaign in U.S. and foreign business publications, and
- Supporting efforts to modernize as well as develop port facilities to meet future needs.

Currently, we are developing a 120-page guide to Illinois Basin coal for use by overseas importers. The guide includes coal specifications, mine and reserve information, and information on coal-producing area companies. It is being printed in four languages -- English, French, Spanish and German. The book should be available late this year.

In conclusion, it should be stressed that the current glut in the coal market does not mean ICG will abandon its efforts to promote Illinois Basin coal. We believe this commodity is a valuable resource for the Midwest. We can market this product -- if we have the imagination, the energy, and the commitment.

12. Coal: Opportunities and Constraints

Charles E. Bond
Vice Chairman
Illinois Coal Association

All of us have read stories and have heard comments pertaining to coal over the past ten years. I would like to briefly point out the areas the Illinois Coal Association believes to be important in analyzing Illinois coal.

First, there is an abundance of it -- roughly 180 billion tons of coal resources underlying Illinois alone. It is quite fair to say that Illinois is the Saudi Arabia of coal.

Let me outline the current status of the Illinois coal industry. I would first like to point out some of the major opportunities related to coal in Illinois. First, Illinois is at present the fifth largest coal-producing state. The Illinois Geological Survey estimates that of the 180 billion tons, some 35 billion tons are recoverable through present mining technology. This compares with the 4.8 billion tons mined since 1810. In short, we are truly blessed with a vast supply of a major energy resource in our own backyard.

We have some of the largest companies in the world operating mines in Illinois. These companies are well staffed with highly skilled and trained individuals who can produce Illinois coal safely. We are also fortunate to have a very high BTU coal, at least in comparison to Wyoming coal. For example, one ton of typical Illinois coal produces as much heat as 1½ tons of typical Wyoming coal. Illinois also has an excellent transportation system through both rail and water for moving Illinois coal to other consuming states as well as to major port facilities for exporting coal abroad. Illinois still is considered one of the logical states for development of major synthetic fuel demonstration plant facilities. One of the key reasons is that we have abundant water resources located in the coal fields. Even though we are currently in a coal slump in Illinois with approximately 3500 miners out of work, the 47 major Illinois coal mines now operating have the capacity to produce an additional 15 million tons annually without any mine expansion. All of this adds up to opportunities for Illinois coal.

Now, what are some of the handicaps placing more and more major constraints on the production and use of Illinois coal? Up until 1969 the coal industry was

virtually unregulated. However, developments since that time, starting with the enactment of the Coal Mine Health and Safety Act of 1969, have made this industry one of the most heavily regulated. For example, here are just a few things that have placed great limits on the Illinois coal industry in its efforts to move forward. The Federal Clean Air Act of 1970, along with the major amendments in 1977, has undoubtedly been one of the single biggest factors in the displacement of Illinois-produced coal. In 1971 there were only some 2 million tons of coal being imported into Illinois. At the end of 1982 we anticipate roughly 19 million tons of western coal will have come to the state during the year. This is one reason the Illinois coal industry has been stagnant for the past 12 years. In other words, we produced 65½ million tons in 1972. Yet, our closest annual tonnage since then was about 63 million tons. Furthermore, 1982 is looking rather dim with 58 - 60 million tons expected. The real issues, or perhaps the single most important constraint facing the industry, concerns this question -- How do we meet all federal and state mandatory requirements and stay competitive? Since 1977 we have closed down nine large coal mines in Illinois because of our failure to stay competitive. The 1977 Federal Surface Mining Control and Reclamation Act has put Illinois at a disadvantage on reclamation costs in comparison to the other states because of the many prime farmland areas in Illinois. In West Virginia or in western Kentucky, Pennsylvania or Ohio, Montana or Wyoming, the overall reclamation cost is between $5,000 and $7,000 per each mine acre; yet, under Illinois conditions, the average reclamation cost can exceed $14,000 per acre. Other disparities have come about in terms of permit application fees. For example, under present permit application fee costs an Illinois operator will spend anywhere from $25,000 to as much as one-quarter million dollars in order to meet the requirements for attaining a permit. In addition, bonding costs have become almost unmanageable.

These costs pertaining to Illinois operations are extremely high compared to the costs in most other states. Another area that has been of great concern to Illinois coal producers over the past few years has been that of productivity. In 1972, average Illinois coal mines -- both surface and underground -- produced roughly 26 tons per man per day. This is in contrast to 11.4 tons per man per day in 1980. Fortunately, the productivity trend in Illinois has been gradually rising since 1978. Thus, briefly this is a glimpse of the picture of the Illinois coal industry during the

past 10 years or so. However, this does not by any means cover all of the developments which have had a direct or indirect impact on the mining and marketing of Illinois coal. Also, over the past few years, many other issues that could have been or still might be very detrimental to the industry -- both in the federal and state arenas -- have been temporarily set aside due to the plight of the industry.

For instance, one issue that keeps coming up in the Illinois Legislature is a coal severance tax. The industry has continuously opposed enactment of a state coal severance tax. We have tried in every area to protect the Illinois coal market and at this particular time we see a state coal severance tax as being an additional step toward making Illinois coal less competitive with its rivals.

In summary, the Illinois coal industry will continue to move as aggresdively as possible to play a larger role in meeting the nation's energy needs. The industry has never been better prepared to do its job. It just needs a chance -- a chance that should come with increased public confidence in the industry and understanding of its necessary role. Given those conditions, I assure you the industry will do its part.

13. Capital Markets, Finance, and Illinois Coal

Wallace Wilson
Energy Consultant
Chicago

There is a perception, evidently rather widespread, that somehow the health of the coal industry is or could be affected adversely by the relative availability of capital with which to finance new development or expansion projects. This concern is especially noted whenever there is consideration of new legistation in the Congress which might impact coal producers, or at conferences, where the economic health of some part of the coal industry is being considered.

It may be stated categorically that the economic condition of the Illinois coal industry has not and will not be affected, to any substantial degree, by the willingness of commercial banks or other sectors of the capital markets to finance projects that have the earmarks of economic success. Obviously, prudent investors will not have much interest in speculative ventures with high potential for failure. Coal mining still retains much of its historic tendency to show cyclical performance, and clearly it is now in a downdraft along with the rest of the economy. But knowledgeable lenders are quite aware of the risks of such circumstances and coal financing usually is structured to accommodate the possibility of some bumps in the road.

The basic ground rules that apply to the financing of any project such as the development of a new coal mine are the same now as they have been for many years, and they can be summarized quite simply. The reserves dedicated to the project must be well defined and adequate for an operating life well in excess of the indicated payout of the financing. The mining conditions must be reasonably predictable, so that extraction costs may be projected with acceptable accuracy. Finally, the projected output must have a well-defined market, at prices which are more than enough to cover all costs of operation including debt service, with a future profit adequate to maintain the incentive of the operator.

Economic downturns, such as the present recession, place additional emphasis on the necessity for phasing out all money-losing operations, giving very close attention to all expenditures and taking any other possible steps to conserve capital and increase profitability. These and similar measures have

resulted in the loss of about 40,000 coal mining jobs throughout the country, about 3,000 of them in Illinois. Assuredly, one cannot minimize the difficulties which such measures have created, but on the other hand it is appropriate to recall that in other periods of comparable economic stress most shutdowns have been of relatively short duration and were followed by longer periods of expansion. Coal mining is demand-oriented, since it is impractical to mine coal solely to build up inventories in advance of firm purchase orders. This means that the present period of difficulty will not abate until orders for coal increase.

Fortunately some companies have been able to scramble for new or different markets for much of their output, with considerable success, and the health of the industry is much better than it otherwise might have been. As discussed in the September 17, 1982 issue of Forbes, some larger companies that traditionally have been major suppliers of metallurgical coal have abandoned much of this market and have contracted to sell this premium product to electric utilities in the East and in overseas markets, either as a compliance coal or as blending stock for achieving compliance. Other producers of steam coal have sold substantial quantities of their coal to overseas buyers, despite the inadequacies of terminal facilities along the East coast. Still others have simply worked harder to market their output, to both new and conventional consumers, with considerable success.

Most Illinois coal is sold to fuel electric utility plants, many of them outside the state, pursuant to long-term sales contracts. Growth in demand for electric power has been essentially flat for several years, and new coal sales contracts for Illinois coal have been few and far between. At the same time the utility industry has been afflicted with a host of other problems, many of them being the fallout from the rapid increase in all fuel prices since the 1973-74 Arab oil embargo. For example, several large utility companies have come under attack for having entered into long-term coal purchase contracts for volumes based upon now-obsolete projections of demand growth, when in the clear 20-20 hindsight of today they might have relied upon spot or other markets at lower prices. Others have been criticized for maintaining large coal stockpiles, thereby increasing their need for short-term financing and increasing interest expense. A number of self-appointed consumer groups have organized expensive, full-time staffs to intervene into rate cases, re-

search utility performance, and advocate elected commissioners of public service agencies, all for the avowed purpose of delaying or reducing rate adjustments. Regardless of the merit of such measures, there is one certainty--producers of coal and their employees are affected whenever actions are taken that deny electric utilities prompt and adequate rate relief needed for their economic health.

IV

NUCLEAR ISSUES

14. What to Do with Spent Fuel

Victor Gilinsky
Commissioner
Nuclear Regulatory Commission

What are we going to do about the radioactive spent fuel that is piling up at power plants around the country? The storage pools at the plants are filling up and there is, at this point, no other place for the spent fuel to go.

Of course, the spent fuel logjam wasn't planned. Spent uranium fuel was to be reprocessed a year or so after it was discharged, to extract plutonium formed during irradiation. The plutonium in turn was to fuel a new generation of reactors -- fast breeders. So strong was the belief in this breeder-dominated future that the current generation of U.S. reactors was designed with only enough spent fuel storage capacity for a few years of operation. (By contrast, Canadian reactors were provided with up to 20 years of storage capacity.)

The American utilities were happy with this arrangement because it kept them out of the waste storage business. However, a number of problems were obscured by the optimism surrounding the nuclear power industry.

First, there were no breeder reactors to take the plutonium. Second, two commercial reprocessing plants were failures. A larger plant, at the Barnwell facility in South Carolina, was caught up in a new government safety requirement that prohibited transport of liquid wastes. This meant that Barnwell would have to add a waste solidification plant, thereby doubling the overall cost. Such a plant was never built. Third, the government was getting nowhere in providing a repository to accept the highly radioactive waste for permanent storage.

Then, in October 1976, for international security reasons, President Ford decided that commercial reprocessing should not proceed until we were confident we could prevent diversion of commercial plutonium to bomb use. To keep our domestic policy in line with our international policy, he decided against a government subsidy for Barnwell's waste solidification facility. This effectively put an end to commercial reprocessing in the United States.

By 1977 it was clear that the nuclear waste storage problem had become a spent fuel storage problem, but the utilities still thought they could count on the federal government. Indeed, in 1977, the

Department of Energy announced that it planned to accept spent fuel for storage at future government central storage facilities. But the proposed legislation was never enacted, and in 1981 a new Administration withdrew the 1977 promise and left the utilities to their own devices.

In these circumstances it is natural to ask: Can plants expand their individual storage capacities rapidly enough over the next few years to avoid curtailing reactor operation? And, to what extent can they count on the government's plans for permanent storage for the more distant future?

SPENT FUEL STORAGE AT REACTOR SITES

Realizing that they would have to provide for themselves, most utilities have found ways to expand expent fuel pool capacity, principally by installing new racks which permit closer spacing of spent fuel assemblies. This method, when fully exploited, usually allows about a three-fold increase in storage capacity. Just about every U.S. nuclear plant has reracked, some of them three and four times. Out of 88 applications for reracking, 81 have been approved so far by the Nuclear Regulatory Commission. In addition, two utlities that had run out of space at one reactor received permission to ship spent fuel to another reactor in their system.

The utilities have been able to exercise sufficient ingenuity, and the NRC has been able to review and approve applications for expansions sufficiently quickly that no power plant has had to curtail operation because of inadequate spent fuel storage capacity.

At times this has meant dipping into the plant's full core reserve -- the storage capacity maintained to permit emptying the entire reactor core if necessary for inspection or repairs. Maintaining such a reserve is obviously good practice, but it is not an NRC safety requirement. In any case, through application of these measures, almost all plants will get by until at least 1990.

NEW TECHNIQUES: ROD CONSOLIDATION AND DRY CASKS

To go beyond that, however, will require new storage techniques or construction of new facilities. In order of estimated cost, these include rod consolidation, dry cask storage, and construction of new spent fuel pools outside the reactor.

Rod consolidation involves dismantling or cutting apart the fuel assembly -- which in a pressurized water reactor contains two to three hundred fuel rods -- and putting the fuel rods closer together in about half the original space. The cost is relatively modest. However, this process involves a good deal of mechanical work on the fuel underwater in the spent fuel pool, and reliability and safety need to be proved. Maine Yankee has submitted an application to NRC for permission to consolidate spent fuel, and several other utilities are considering it.

More expensive, but still cheaper than building a new pool, is putting spent fuel, which has cooled for 5 years, in large dry casks. A typical cask might hold 10 tons of spent fuel, weigh close to 100 tons, and cost about one million dollars. Cask capacity could be roughly doubled if the fuel were first consolidated. Ideally, such casks would also meet transportation requirements. Then, once the spent fuel was sealled inside the cask, it would not need to be opened before it reached a repository for permanent storage. In the meantime, it could remain at the reactor site or at some interim location. We expect an application soon from the Virginia Electric Power Company for such a storage scheme at Scurry.

This approach to the storage problems at reactors raises some optimism. If approved and adopted, it would essentially solve the problem of how to store spent fuel safely at reactor sites so as to avoid interrupting reactor operations. So far as can be determined, there would then be no practical limit to the amount of spent fuel that could be stored at most reactor sites.

LONG-TERM WASTE DISPOSAL

It is not, however, planned to leave the spent fuel at the reactor sites indefinitely. It has always been assumed -- in fact this was the basis on which power reactors were licensed for operation -- that the government would at some point accept the waste for permanent storage in a federal repository.

The trouble is that the date for this has kept receding. Most are no doubt familiar with the dismal history of the federal government's efforts toward this end. The plan in the 1960's for a repository in underground salt formations was switched in the early 1970's to a plan for a surface repository, which was abandoned in the next administration in favor of a return to the underground approach. Since then, the details have varied from administration to adminis-

tration with the result that we are still not in sight of a repository.

The federal responsibilities are clear. The repository design has to be approved by the NRC from the point of view of public health and safety, and protection of the environment. NRC requirements must be based on overall standards set by the Environmental Protection Agency. The Department of Energy is charged by law with developing the needed technology and building a repository.

Some progress has been made. The first procedural part of the NRC's regulations on repository licensing was published in final form in February, 1981. The other part, the set of technical performance standards to be met by the repository, was published for comment in July, 1981, and is now being put in final form by the Commission. Unfortunately, this is being held up by the EPA's failure to issue its standards.

Our rule calls for a detailed study of each site, including use of underground exploration. A minimum of three sites, including at least two kinds of underground media must be studied. DOE expects to do this in basalt, at Hanford, Washington; in tuff, at the weapon test site in Nevada; and in salt, at a location yet to be picked. DOE expects to sink shafts at these three sites in 1983 and to select a repository location by 1987 or 1988. The schedule calls for a construction authorization by 1992 and a respository ready for business in the late 1990's.

A bill on this subject has passed the Senate, and a similar bill is before the House. It will likely be passed in the post-election session, although it is unclear whether the differences can be resolved in time to enact legislation this year. These bills would essentially confirm the current DOE schedule and would set up a mechanism for resolving state-federal differences over the placement of a repository. Needless to say, no state is particularly enthusiastic over the prospect of hosting such a repository. The states, having had some unpleasant experiences, simply don't trust the federal government on this issue.

Even if these plans are realized, it would take some years for a repository to absorb the spent fuel in reactor storage pools. So, for at least the next twenty years, the nuclear waste problem is the problem of where to store the spent fuel. The cumulative amount, to the year 2000, is estimated by DOE to be about 70,000 tons, or nearly ten times the amount already discharged. A typical reactor, by the way, discharges about 30 tons of fuel a year, so the hundred or so reactors expected to operate twenty

years from now will add about 3000 tons per year to the DOE total.

In planning for the interim, how much confidence can we have in the government's nuclear plans for permenant waste storage? Or, how long do we expect the spent fuel to remain in temporary storage?

The NRC Commissioners were asked by the Court of Appeals, in effect, whether they were confident that spent fuel will be removed from reactor sites by the end of a reactor's operating life. The Commission is in the process of providing the Court with an answer.

Much as it is hoped that current plans will work out, there have been too many failures and delays in federal nuclear waste planning to be confident of any schedule. The proposed legislation, if passed, would help provide some impetus and might help resolve state-federal disputes in a reasonable time. But there would still be a long way to go. Public attitude on this subject is volatile, and many political accommodations remain to be reached. And, it does not help that DOE, the agency that is supposed to carry out the program, is slated for extinction by this administration.

The conclusion is that the country should plan on providing interim spent fuel storage for several decades.

WHAT ABOUT THE INTERIM?

It has been seen that there is essentially no practical limit to the amount of spent fuel that could be stored at most reactor sites. This doesn't mean, however, that it would be a good idea to leave it there, especially after the expiration of the site's operating license. The utilities are in the power business, not in the waste storage business, and we cannot depend on all of them to ensure adequate protection of the spent fuel when their sites are no longer producing power. Moreover, spent fuel remaining in a reactor storage pool after final shutdown complicates cleanup and decontamination.

It is better not to retain the spent fuel even at an operating reactor, if there is a reasonable alternative. There are already enough things to distract station managers from their principal responsibility -- the safe and reliable operation of the reactor.

From the point of view of health and safety, it would be preferable for the spent fuel to be collected from the reactor sites, probably in dry storage casks, and stored at a central facility where it would get

better supervision and where it would not interfere with reactor operation.

The waste bills in the Congress do contain some provisions for spent fuel storage away from reactors -- but only for about 3 percent of the expected inventory in the year 2000. This is a kind of "last resort" storage; I would make provision for central storage of the bulk of the spent fuel.

The argument is made that if such an interim storage facility is set up, all the steam will go out of the effort to build a federal repository for permanent storage. This would, however, apply equally to extended storage at reactor sites. There is also strong opposition to movement of spent fuel and an inclination to put it off as long as possible. Finally, no one wants to host a site for such a central storage location, any more than they want to host a site for a permanent repository.

Incidentally, the radioactivity of spent fuel is diminished by about a factor of 100 in the course of the first year after discharge, and by about another factor of 10 over the next ten years. That means that after 10 years the spent fuel is about 1,000 times less radioactive than when it was first removed from a reactor core. This in turn means that any waste storage facility is relatively benign compared with a power reactor. There has been a lot of exaggeration of the dangers of commercial spent fuel storage and disposal.

What worries people most is that they know that waste dumps of all sorts are often neglected, and they fear this is also likely to be the case for nuclear waste. Their confidence in government oversight has been further undermined by such things as the leaks in the military waste tanks at Hanford and the flip-flops in government waste policy.

This brings up the latest of the flip-flops -- the government's renewed romance with reprocessing and the encouragement of the use of plutonium fuel in place of uranium. This amounts to a reversion to the policy of the 1960's.

REPROCESSING

Whatever may have been the case before, reprocessing no longer makes any commercial sense. Plutonium can only compete when uranium is very expensive. But there is much more uranium than anyone thought years ago, and the number of reactors expected to use it is much diminished. As a consequence, the price of uranium has been falling. So much so, in fact, that

Congress is talking about limiting imports. No commercial reprocessing plant will operate without massive federal subsidies.

Not only is this an embarrassing inconsistency between the Administration's nuclear ideology and its free enterprise rhetoric, but the perfectly straightforward problems of providing for spent fuel storage have now been entangled with reprocessing. For example, the Administration withdrew support for an interim storage facility because it "would detract from efforts to stimulate commercial reprocessing."

DOE insists that reprocessing is the solution to the spent fuel storage problem. They are talking about commercial reprocessing being available in 1992, even though they must know this can't happen because the Office of Management and Budget declines to provide a subsidy. All of this is bound to introduce confusion in spent fuel storage planning by utilities.

Entangling spent fuel storage with reprocessing is how we got into trouble in the first place. We allowed the apparent inevitability of fast breeders to dictate the size of spent fuel pools in light water reactors. This time around, let's not permit spent fuel storage to be hostage to grandiose nuclear schemes. Whatever else we do, let's make sure we have adequate spent fuel storage.

15. Nuclear Waste Management: A Federal Perspective

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This paper will highlight some recent legislative, techical and operational developments. Nuclear and hazardous chemical waste management issues have much in common. Both were once considered trivial by many of the developers of the sophisticated technologies that give rise to these wastes. They were initially dealt with much like municipal and industrial wastes: shallow land burial, whether or not these wastes might have required longer term confinement than a burial ground can assure. Today we have the knowledge to tailor the disposal technique to the hazards of the waste, the technology to do the job, and we can get the resources to do it right.

This is not a true technical breakthrough. No new principle of the physical sciences had to be discovered; no Nobel prize is likely to be won for waste-related science or technology. The knowledge and talent in geology, hydrology, chemistry, and physics were already available but had to be put to work to tell the engineers what to design and build and how to operate facilities. Today we are designing, building and already operating new facilities and pilot plants.

This list of tasks in nuclear waste which "nobody has ever done" is getting shorter as more and more parts of the waste disposal system are being demonstrated. But even with all of the technology and resources in hand, with all the demonstrations of success, the job may not get done. The same public attention to nuclear and chemical waste management which has brought technical and management talent and financial resources to bear on this task can also keep it from getting done. This attention manifests itself in several ways.

Nuclear radiation is perceived as a serious hazard, and it certainly can be a serious hazard. Nuclear operations should therefore be safe, and they are unusually safe but not absolutely so. Nothing is absolutely save, however, the risk must be made small enough to be acceptable.

No matter how safe a project may be, few people offer to have sewage treatment plants, landfills, let along hazardous chemical or nuclear waste facilities sited near their homes. After all, most people reason

this is a big country, take the waste somewhere else. Unless we, as a country, wish to continue to ignore the waste management tasks, we must take steps to site the necessary facilities somewhere. Beyond safety, we must assure that siting is an objective, public, and fair process, and that communities near any facilities have insurance against harm or financial loss.

Where do we stand today in dealing with nuclear waste? The Congress has set policy for low-level commercial wastes and will soon set policy for high-level wastes. The states are responsible for dealing with low-level wastes and are authorized to form compacts to do so jointly. The federal government remains responsible for high-level commercial wastes, as well as for all of its own wastes. The user and beneficiary of the nuclear activities that generate the wastes will pay the price for their management. Siting of high-level waste facilities will be a carefully delineated process with opportunities for participation by affected local and state officials with provision for a presidential decision and some form of congressional review and consent or dissent. Sites in several geologies and regions are under investigation.

For its own wastes, the federal government is building a pilot plant for long-lived transuranic wastes near Carlsbad, New Mexico, in bedded salt and a full-scale plant for immobilizing its high-level wastes in Savannah River, South Carolina, for future disposal in a federal repository. This plant will handle 70 percent of the defense high-level wastes which are stored in tanks in this country. The product will occupy about 20 acres in a 10,000 acre federal repository.

Some of the materials in "waste" can be recycled for re-use or new applications. For example, penetrating and hazardous radiation comes from radioactive cesium. Concentrated cesium, recovered from waste in Hanford, Washington, will be used by the City of Albuquerque for sterilizing sewage sludge. This treatment does not make the sludge radioactive in any way but destroys pathogens effectively. The sludge will be used as fertilizer on city property. It is also possible to disinfect food without leaving behind traces of carcinogens as do present methods.

In another example, the noble metals, rhodium and palladium, arise as byproducts of the fissioning of uranium and plutonium. By the end of this century there will be several billions of dollars worth of these materials in nuclear "waste." Their use in catalysts in the petroleum and chemical industries,

and their origin (97 percent imported from South Africa and the Soviet Union) give them strategic importance. We expect to separate about $30 million worth of these materials from the Savannah River high-level waste at virtually no cost to the government and will add them to the strategic reserve. They will require refining before being usuable.

The states and the federal government share in the responsibility for managing nuclear waste safely, effectively, and rationally. We can get the job done if we cooperate; we will flounder if we don't. I am looking forward to a constructive federal-state partnership in this area.

16. Nuclear Waste Management in Illinois

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Director
Illinois Department of Nuclear Safety

This paper will address nuclear waste production and its management from a rather parochial standpoint, namely the issue as it now exists in Illinois. Controlled nuclear fission was first achieved here in Chicago in 1942 under the West Stands at the University of Chicago. This demonstration produced nuclear waste. Prior to 1942, naturally, radioactive materials (primarily radium and thorium) were used in various medical and commercial applications within the state and they all produced radioactive waste in one form or another.

The generation of man-made radioactive waste has increased substantially since 1942. Today there are seven commercial nuclear power plants in operation in Illinois which in the aggregate produces in excess of 6000 megawatts of electric power. This generating capacity provides about 50 percent of the electrical needs in northern Illinois and about 23 percent on a state-wide basis. We also have significant use of radioactive materials in industrial, medical, academic and research applications. All these activities produce radioactive waste in varying degrees.

Basically, the radioactive waste forms confronting Illinois, as well as the nation as a whole, fall into one of three categories. These are:

- Radioactive waste from pre-nuclear era activities.
- Spent nuclear fuel.
- Low-level waste (LLW).

By definition, wastes from categories 1 and 3 are low level in nature and hence their management and disposal are a state responsibility. Spent nuclear fuel is at present a federal responsibility, although in Illinois it is also an area in which the state is concerned.

Much of the waste from pre-nuclear era activities is associated with commercial activities which are now defunct. Radioactively contaminated buildings and their surroundings are the residue. Ultimately this radioactivity may either be placed in a commercial low level waste disposal facility or buried and stabilized on site. The costs of such cleanup and disposal may

well be borne by the taxpayer, and hence are a source of considerable controversy and concern.

In regard to spent fuel storage, the nuclear power plants in Illinois have on-site storage capacity sufficient to accommodate fuel storage needs into the 1990's. The away-from-reactor (AFR) storage facility operated by the General Electric Company at Morris, Illinois has a storage capacity of 700 metric tons (MT) and is about half filled. When current commercial contracts are complete, the facility will be 80 percent full. State concerns center about the possibility that the GE-Morris facility may become a federally operated AFR (a matter which will be resolved by pending federal legislation) and the fact that current Illinois law prohibits the shipment of additional (beyond the present 350 MT) spent fuel to GE-Morris for storage.

In 1980 Illinois generated 8000 cubic meters of LLW which contained 11,000 curies of radioactivity. In terms of volume generated, Illinois was third nationally; in terms of radioactivity we were sixth. By volume, 70 percent of the LLW came from the nuclear power operations, and the remaining 30 percent was equally divided between industrial and institutional sources. In terms of radioactivity, 80 percent came from nuclear power operations. All Illinois generated LLW is shipped out of state for burial. Again using 1980 as the representative year, by volume, 60 percent of our waste went to Hanford, Washington for burial, 30 percent to Barnwell, South Carolina, and the remaining 10 percent to Beatty, Nevada.

From 1966 to 1978 a commercial LLW disposal facility operated at Sheffield, Illinois. During operation slightly in excess of 3 million cubic feet, containing 260,000 curies of LLW, were buried at the site. Nearly 70 percent of the waste came from Illinois generators. The licensed site was filled in 1978; the site is now closed and is undergoing decommissioning procedures.

With the present involvement with nuclear-related activities, Illinois will continue to be a major generator of LLW. Hence, the Congressional directive under the Low Level Waste Policy Act of 1980 has special significance to Illinois. Illinois is not a potential party to any regional compact centered about an operational LLW facility. We have been engaged in developing a Midwest Regional LLW compact with 15 other states. We are also examining the possibility of developing and operating an Illinois-only LLW disposal facility. A prerequisite to either option is the timely decommissioning of the Sheffield facility.

The challenge is great, and the need is critical. The next few months will require the utmost effort and common sense, if Illinois is to provide an effective means for the disposal of LLW generated within its borders.

17. Basic Issues of Nuclear Safety

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Vice President - Water Reactor Divisions
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The commercial nuclear power industry is celebrating its Silver Anniversary this year. Anniversaries are a time to reflect on the past, and in the nuclear industry we can do so with pride in our achievements. From the time the Shippingport plant went on line in 1957, nuclear power reactors have produced electricity with an excellent safety record. Whether you measure safety by strict design standards, degree of regulation or low impacts to public health, nuclear energy will rank high on the list. My viewpoint is based not only on the record of safety, but also on my experience as an engineer. A general principle to keep in mind is that safety is not an absolute, like the number of ounces in a pound, but is a relative concept which needs to be considered in a number of different aspects.

In the first place, safety or risk cannot be considered isolated from the benefits of an activity. The oil embargo of 1973 is a dim memory and the public has apparently forgotten the dramatic increase in the price of oil which accompanied the crisis in Iran.

In 1973, Americans spent only $8 billion for imported oil and despite conservation measures, the total cost for imported oil in 1981 rose to $80 billion. Does this country want to continue to depend on foreign energy sources, or do we want to utilize more of our domestic resources? I believe the latter view is held by the majority of Americans and which is reflected by the drop in total energy use and in the increase in electricity use which can utilize domestic resources for power generation. We need to put America back to work and we need to do it using domestic sources of energy such as coal and uranium, as well as conserve and develop advanced energy sources like solar and fusion.

Secondly, all activities have risks as well as benefits. There are no risk free energy sources to be tapped. Even conservation produces risks such as the death rate for smaller cars and the impacts of indoor pollution. All of the energy technologies, including solar and other renewables, will produce some health and environmental impacts. This does not mean that these should not be developed. It does mean that the risks and environmental impacts of these technologies will have to be accepted along with their benefits.

The greatest risk of all may be not having enough electricity to keep the factories running and power our cities. In 1965, a few days without electricity in New York resulted in several deaths and about $1 billion in property damage. Abundant electricity supplies are not only needed for economic growth, but also to maintain the fabric of our society.

Thirdly, safety can always be increased, but at a price. Since zero risk is impossible to obtain, the search for safety can become a never ending quest for its own sake. In any society there are finite limits to the time and financial resources available for the reduction of risk. The effort required to reduce the already small risks of nuclear power to even lower levels is not cost-effective. Time and money is not available to be used where it could do some significant good, such as in auto safety. I will now apply these ideas to a number of what are perceived as nuclear safety issues.

RADIATION

Fear of radiation stems from lack of information and from misinformation. Most people associate radiation with the mushroom cloud from a nuclear weapon. More subtly, their misinformation is based on movies and TV shows in which impossible monsters like Godzilla, Slithis and the Incredible Hulk originate from an accident with radioactive processes. Radiation is seen by some as mysterious because it cannot be seen, tasted, felt or heard. However, it can be measured very accurately. The important fact that must be presented is the difference between large amounts of radiation that can be harmful and the significant amounts associated with commercial nuclear power plants.

Radiation, by definition, is "energy emitted in the form of waves or particles." The term covers a variety of phenomenon including ordinary light, medical X-rays, the microwaves used to cook food and the ionizing radiation released when the nucleus of an atom changes by decaying to a more stable state.

Radiation is the result of completely natural processes and has been part of the physical world for as long as the earth has existed. We are exposed to radiation daily from sources such as cosmic rays and radioactive materials in our natural environment.

Radiation has been studied by national and international organizations since its discovery in 1896. The Surgeon General of the United States and noted epidemiologists have stated that we know more

about the health effects of radiation than most of the toxic elements in our environment. We have known, for example, for many decades the effects from radiation are related to the amount of exposure.

To put radiation into perspective, we compare natural or background radiation to which large populations are exposed. (Figure 1) Different populations receive different amounts depending on altitude, latitude and radioactive components in soil and water. these exposures vary by a factor of 50! People living in Denver receive twice what the average American gets. People in some parts of India, China and South America get up to 50 times what the average American gets. Studies of these groups have shown no health effects (somatic or genetic) attributable to the radiation background. A person living within five miles of commercial nuclear power plant receives less than 1 percent of the average background exposure.

For very high amounts of radiation, 200 to 5,000 times the average background exposure, we know that health effects do occur. We know that from studies of medical treatments, early radiographers and Japanese

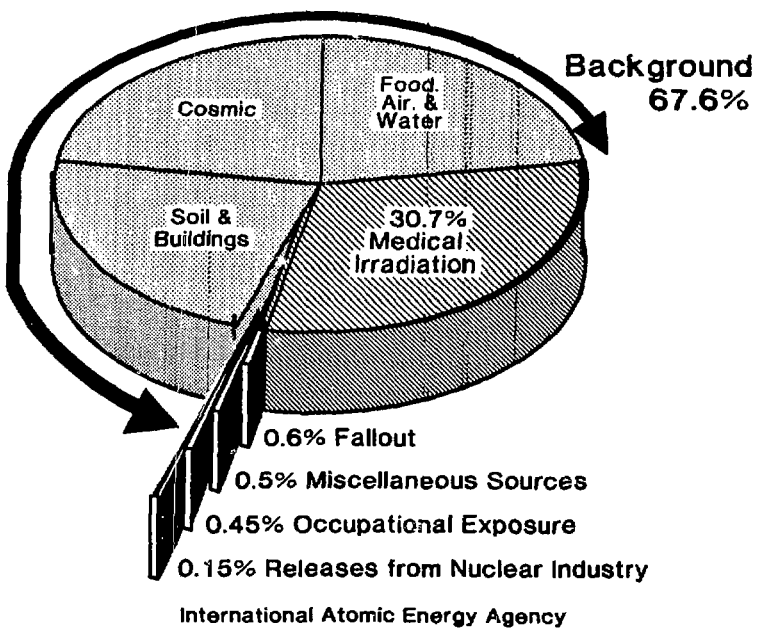


FIGURE 1 AVERAGE INDIVIDUAL RADIATION EXPOSURE MOSTLY BACKGROUND

A-bomb survivors. From these and other studies, we have seen no evidence of damage at low amounts such as ten or twenty times the average background.

During 25 years of commercial nuclear electricity generation, we have accumulated many thousand man-years of safe work with radiation sources. These added to work in the defense establishment and the nuclear navy have proven that we know how to design our plants and our procedures to protect both workers and the general public and such protection has been a major factor since the beginnings of commercial nuclear power.

NUCLEAR SAFETY BASICS

Two essential principles of nuclear safety are to keep the nuclear fuel adequately cooled through redundant systems and to provide a series of multiple barriers between radioactive materials and the public. Nuclear power plants are designed and constructed to withstand hurricanes, tornadoes, earthquakes and other natural phenomena. They are designed to safety shutdown in the event of mechanical failures and they are designed to prevent the release of radioactive materials.

Nuclear fuel produces heat by controlled fission. Nuclear fission occurs when a neutron is absorbed by the nucleus of an atom, causing it to split into two smaller parts. In the fission process, energy is released, and enough neutrons are also produced to initiate other fissions, a chain reaction. Because they are capable of sustaining the fission process, uranium-233, uranium-235 and plutonium-239 are called fissile materials that can be use as nuclear fuel. The elements that result form the fission process, such as cesium-137 and strontium-90, are called fission products.

There are fundamental physical reasons why a nuclear reactor cannot explode like a nuclear weapon even though nuclear weapons and nuclear reactors rely on the fission process to work. In a nuclear weapon, the goal is to get as much energy released as possible over a very short period of time, employing as little weight of material as possible. To accomplish this in nuclear weapons, specially designed and fabricated components, composed of essentially-pure plutonium-239 or uranium-235, are smashed together in as small a volume as possible in the shortest possible time to initiate the nuclear chain reaction. For a nuclear reactor, by contrast, the goal is to control the generation of energy in the fission process and

extract the heat as it is generated. Accordingly, the concentration and purity of fissionable material in a bomb is very high (greater than 90 percent), whereas it is quite low in a nuclear reactor (approximately 3%) and distributed over a large volume.

The fission of nuclear fuel occurs in specially fabricated cylindrical fuel rods located in the reactor vessel. In a Westinghouse pressurized water reactor, the water under pressure circulates through the reactor and enters a separate water system turning the water into steam, and the water originating in the reactor is returned to the reactor at a lower temperature. The steam from the steam generator turns the turbine and from this point on the nuclear-fueled plant operates the same way as the coal-fueled plant (see Figure 2).

During the operation of a typical nuclear power plant, the decay of the fission products can produce as much as 7% of the heat generated by the nuclear fuel; the other 93% of the heat is produced by the fission process. When control rods are inserted, the fission process stops producing heat but 7% of the heat due to radioactive decay continues for awhile. Consequently it is necessary to keep the reactor cool for a time even after it is shut down. After five hours, the decay heat has dropped to 1% of the original heating that the reactor produced when it is at full power.

The basic philosophy of nuclear reactor safety is to provide several levels of safety which are incorporated into the safe design, construction and operation of nuclear power plants.

The first level of safety is to design components that will operate with a high degree of reliability. An important part of reactor design is the concept of "multiple barriers" against the escape of radioactive fission products into the environment (see Figure 3). The first barrier is the fuel itself. Since the fuel is a ceramic, the solid fission products are trapped within the structure of the fuel pellets. The second barrier is the fuel cladding, the sealed metal tubes which enclose the fuel pellets. The reactor coolant system, which included the reactor pressure vessel and the associated pumps and piping, forms the third barrier. Also, the reactor containment structure, made of steel and concrete, provides the ultimate barrier against the escape of radioactivity. Protection also is provided by the distance between the reactor and the public.

Another important consideration in reactor design is the use of "redundancy". Redundancy refers to the provision of two or more components or systems so that

PRESSURIZED WATER REACTOR (PWR)

Figure 2

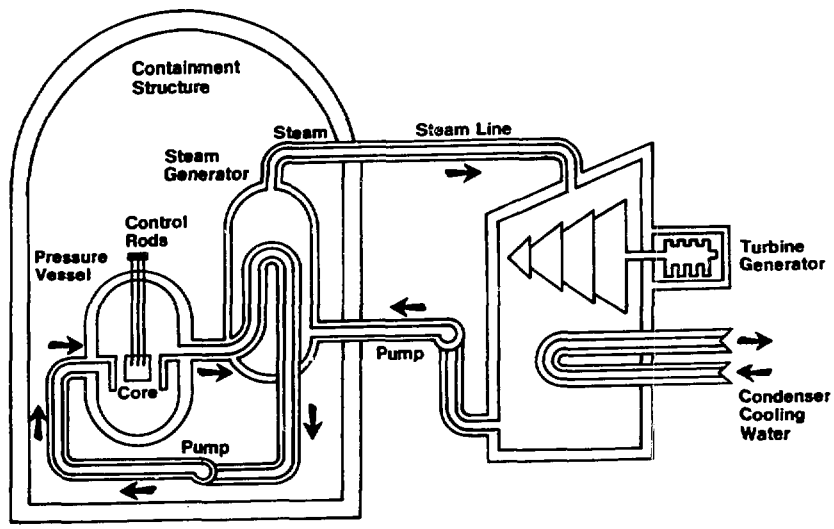
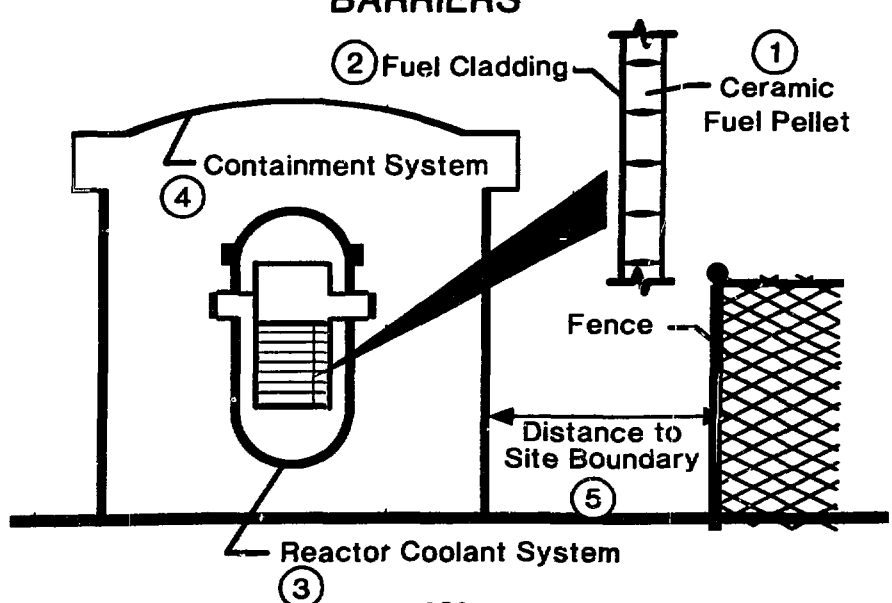


FIGURE 3 MULTIPLE RADIOACTIVITY BARRIERS



the reactor can operate or safely shut down in the event that one of the components or systems fails. There are many redundant components and systems in a nuclear power plant. For example, at least two transmission lines are available from two different offsite power supplies in order to provide a reliable source of power when the plant is shut down. As a backup, there are at least two diesel generators, each of which is capable of providing sufficient electric power for necessary safety equipment in the event of an accident.

The protection system, which serves as the second level of safety, is designed to prevent, arrest, or safety accommodate a range of abnormal conditions. Deviations from normal operating conditions, called transients, can arise from a variety of causes. Mechanical equipment fails, operators make errors and storms cause damage. Most transients in the reactor system are accommodated by automatic controls. For example, instruments can detect changes in reactor power or coolant temperature and automatically adjust control rods or coolant flow. If the transient is more serious, the reactor may have to be shut down. This may be accomplished automatically or manually.

The philosophy of redundancy is employed in the protection system. For example, three or four channels are used to monitor the various operational variables such as temperature, pressure and flow rate. Corrective action will only be taken if two or more channels indicate such action is needed. In addition to redundancy, a philosophy of functional diversity is also employed. Diversity means the use of two or more completely different methods of achieving the same objective. For example, reactor shutdown is based on the input of several variables such as neutron flux, coolant temperature and pressure. The protection system is designed to shutdown the plant safely under conditions which normally may be expected to occur. After the plant is shut down, core cooling is still provided.

Nuclear power plants are also designed to deal with rare but potentially more serious events. The engineered safety features, the third level of safety, incorporate additional mechanical systems and barriers to prevent the release of radioactivity should certain unlikely accidents occur, such as a major pipe break with loss of reactor coolant. The engineered safety features include the emergency core cooling system (ECCS), auxiliary feedwater pumps, various auxiliary components and the containment vessel. The purpose of the ECCS is to prevent the reactor core from overheating in the event of a complete loss of coolant.

The ECCS is designed to inject cooling water into the reactor core if the normal cooling flow has been interrupted. Emergency core cooling systems, in general, have multiple provisions for accomplishing this. In addition to the ECCS, the engineered safety features include several other systems. One such system is a cleanup system to remove radioactive fission products from the containment. The containment building is also an engineered safety feature.

The record of nuclear power has been exemplary with no fatalities or life-threatening radioactive releases to the public after 500 reactor-years of operation in the United States. Over 1500 years of commercial reactor experience world-wide can be added to this outstanding safety record. This is an excellent record, especially when compared to other large-scale energy production activities.

THREE MILE ISLAND

The accident on March 28, 1979, at the Three Mile Island nuclear power plant was the worst accident in the history of United States commercial nuclear power. As a result of a series of mechanical and human failures, the nuclear core was partially uncovered. As discussed previously, cooling water is needed even when the fission process has been terminated to remove the heat from radioactive decay.

The accident at Three Mile Island validated the multiple barrier approach to safety outlined earlier. The amount of radiation that escaped the plant was small; the average individual exposure to a person within 10 miles of the plant was approximately 7 millirem, which is less than one dental x-ray or one month's normal radiation exposure in the area. The major impacts of Three Mile Island were heightened public concern and the financial blow to the utility which owns and operates the plant. It was further recognized that some changes would improve the industry as a whole and minimize the impact of a similar accident in the future.

The immediate response of the nuclear industry to the accident at Three Mile Island was to help at the plant site and to begin implementing the lessons learned at the other nuclear plants. Each utility established a task force to review plants, procedures and people. Because of the role of operator actions in the accident at TMI while the safety systems worked as required, the major emphasis has been on operator training and providing better information to operators. Then industry groups were established to

share information and coordinate efforts. There are three major areas of industry-wide response.

First, the Nuclear Safety Analysis Center (NSAC) was established in May 1979 by the electric utility industry at the Electric Power Research Institute. The initial objectives were to get the best possible understanding of what happened at Three Mile Island, the contributing factors, and the implications in terms of generic safety issues and remedies. In addition, NSAC is cooperating with the State of Pennsylvania in sponsoring studies of possible health and mental effects from the accident.

Second, the Institute of Nuclear Power Operations (INPO) was established in July, 1979 by the electric utility industry. The purpose of INPO is to monitor and improve the operation of nuclear power plants and its focus is on human factors. INPO is working to establish benchmarks for excellence in the management and operation of nuclear plants, and it conducts evaluations to determine that benchmarks are met. In addition, INPO is working to establish various education and training programs for utility and plant personnel; to develop operations and training programs that take human factors into account; and to provide emergency preparedness coordination for the electric utility industry.

Third, Nuclear Electric Insurance, Limited (NEIL) was established in early 1980 to provide part of the cost of replacement power for certain prolonged outages due to an accident. The largest financial impact of TMI has been the cost to the utility, G.P.U., of buying replacement power. The maximum total indemnity is set at $156 million and includes $2 million a week for the first year of an outage and $1 million a week for the second year. Annual premiums for the insurance range from $1.[illegible] million to $1.8 million, depending on the number of units insured. In order to be insured a utility company must receive certification from INPO.

In summary, major changes have occurred in the nuclear industry in response to the accident at Three Mile Island. In particular, significant changes are evidenced in the areas of operator training, instrumentation and display, and safety analysis. Training programs for plant operators have become more intensive, and trainees are required to study a greater variety of malfunctions which may occur. Trainees now receive more basic education in the engineering science of plant design and operation. And, the passing grade level has been increased. With respect to plant instrumentation, the most immediate remedy has been to provide a positive indication of the

condition of relief and safety valves. In addition, several important plant parameters are now displayed visually on a television screen. In terms of safety analysis, the emphasis has been shifted somewhat from high-consequence, low probability events to more probable events such as smallbreak loss-of-coolant accidents and valve failures or malfunctions. A major program has been undertaken to test relief and safety valves. All of these actions should significantly improve nuclear reactor safety. But, they are just part of continuing programs to improve nuclear safety and operating performance.

NUCLEAR WASTE DISPOSAL

The disposal of nuclear waste continues to be a major nuclear safety issue and perhaps no issue is as misunderstood as waste management. During the last decade, the scientific community has repeatedly determined that nuclear wastes can be safely disposed with insignificant risk to the public health and safety.

Public concern has primarily focused on the high-level nuclear wastes produced as the nuclear fuel is fissioned. In considering the safe disposal of high-level nuclear waste declines with time, more than 90% of this activity will decay away in 10 years and more than 99% will be gone in 100 years. When this fact is pointed out, it becomes much more understandable that the hazard presented by high-level waste will be comparable to the original uranium ore in about 1000 years.

A number of waste disposal systems, ranging from disposal in outer space to disposal below the seabed under the oceans, are possible. A recent DOE study, "The Final Environmental Impact Statement - Management of Commercially Generated Radioactive Waste," evaluated these options and concluded that the best approach is a multiple barrier system whereby radioactive wastes will be isolated from the biosphere by:

1. Incorporating the waste into a durable solid form, such as glass or ceramic.
2. Placing this form in a specially engineered canister made of corrosion-resistant materials such as cast iron, stainless steel, cooper, or titanium.
3. Burying the canister in a stable geologic formation such as bedded salt, basalt, granite or volcanic tuff.

4. Backfilling the area with a material such as bentonite, which would act as a buffer between the canister and the geologic medium.

The Committee on Nuclear and Alternative Energy Systems of the National Academy of Science concluded that nuclear waste disposal does not present any substantitive risk potential, even assuming a complete failure of the containers enclosing the waste. The Committee found that the lack of political will to resolve the waste issue is its most serious impediment, as past government action on this issue has been both "dilatory and capricious." This Committee was appointed by the Governing Board of the National Research Council, whose members are drawn from the National Academy of Sciences, the National Academy of Engineering and the Institute of Medicine.

Similar conclusions have been made by other blue ribbon panels looking at this subject, including the American Physical Society and the Ford Foundation's Nuclear Energy Policy Study Group. A number of the safety studies on nuclear waste disposal, performed both in the United States and other countries, were summarized in an article which appeared in the January 1982 issue of Reviews of Modern Physics. The general conclusion of these many technical studies is that even if there is a failure of part of the waste disposal system, the radiation dose to man is only a small fraction of natural background radiation.

The Inter-Agency Review Group established by President Carter concluded that the technology for constructing a waste repository exists and plans should continue for full-scale operations. Projections are that by the mid 1990's, a disposal facility will be in operation. Westinghouse has been working closely with the Department of Energy to make this plan a reality, as evidenced by our involvement with the Waste Isolation Pilot Project in New Mexico. Progress is being made, and the first testing holes have been drilled at the project site.

Progress in the technical arena is beginning to be followed by progress in developing the more difficult institutional framework. In December 1980, the Low-level Waste Policy Act was passed by Congress and signed into law. High-level waste legislation has this year passed the Senate, and all three House subcommittees having jurisdiction over nuclear waste have reported their versions of the bill. If a comprehensive high-level waste bill is to become law in 1982, the three House versions will have to be considered and passed in the November lame-duck session.

RECENT TOPICS

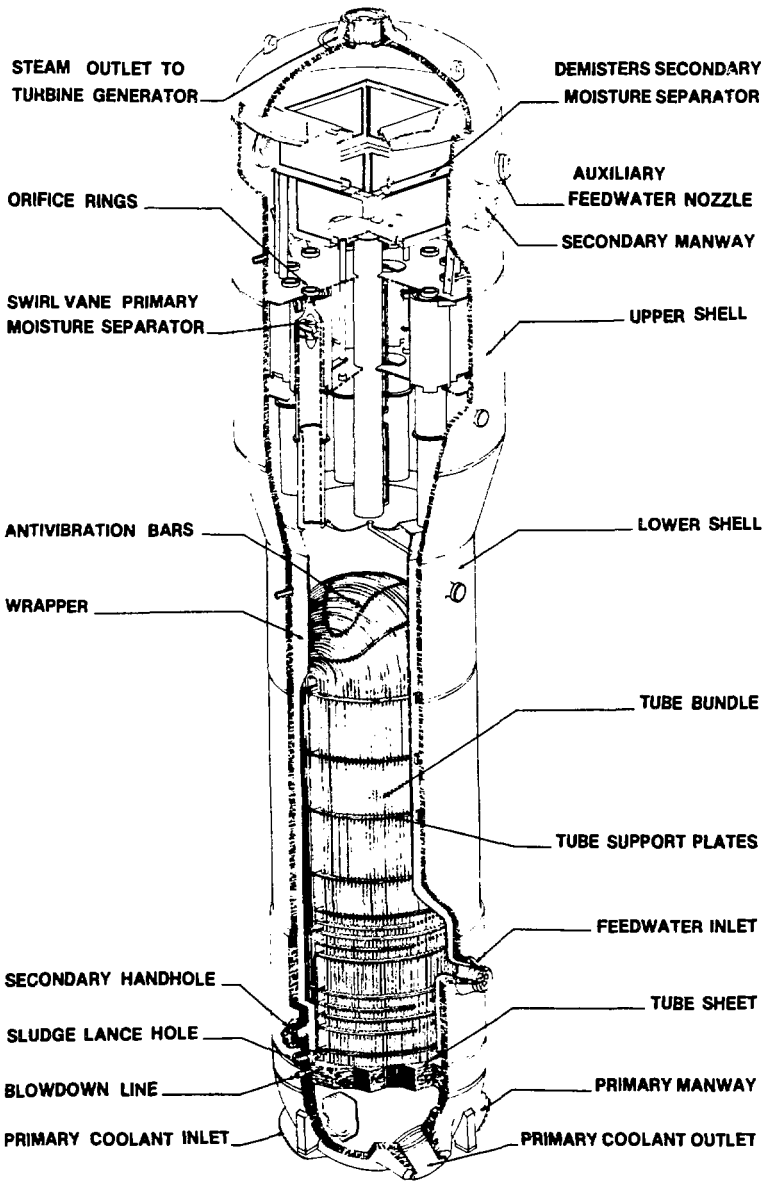
Specific issues tied to the general topic of nuclear safety have recently received considerable attention in the media.

Steam Generators

A steam generator is a 106-foot-tall cylindrical steel vessel containing 4,600 tubes in a "U" shape (see Figure 4). These tubes, typically about 3/4 inch in diameter, act as a heat exchanger. Water from the nuclear reactor core flows through the inside of the tubes, and the heat energy from this primary system is transferred to the secondary or steam system side of the plant. In the secondary system, the heat generates steam that drives the plant's turbine and electrical generator.

Two issues concerning steam generators, which are not safety issues, deal with corrosion and vibration. In the case of corrosion it is important to remember that corrosion is not unique to nuclear plants -- fossil-fired plants, both oil and coal -- because both experience boiler tube corrosion. The key to avoiding steam generator corrosion is to keep good chemistry control in the water. The steam generator is made with corrosion-resistant materials, but even they are subject to attack by acids and caustics. Also, within the last 15 years, the nuclear industry has learned a great deal about controlling corrosion. There is a growing trend toward high-integrity condensers to prevent leakage of impure water into the water that goes into the steam generators. And, newer steam generators use improved designs and materials that provide additional resistance to corrosion. The most important consideration, however, will be water chemistry.

The vibration issue is somewhat more recent. What has happened is that in one design steam generator (called the "preheat" design), water flowing into the steam generator was found to cause the tubes to vibrate and wear permaturely. This phenomenon was identified last fall in a Swedish plant. Westinghouse established a task force of our best designers to investigate and remedy the situation. As we have reported to the NRC, our program for beginning modifications to the first such steam generator is scheduled for this year. The modification will involve installing a device at the inlet to straighten and better distribute the flow. However, the stream generators can operate with reduce flow, prior to repair without wear. This allows plants with preheat steam gene-



MODEL D 3 STEAM GENERATOR

Figure 4

rators to operate at reduced power prior to being modified.

Significant progress has been made by Westinghouse in the repair of steam generators by the application of advanced robotics technology. The corrosion and vibration problems do not threaten the health and safety of the public.

Reactor Vessel Integrity

The reactor vessel in a pressurized water reactor (PWR) is about 40 feet high, 15 feet in diameter and has steel walls 8 inches thick. For normal operation and even abnormal events during a plant's life, there are large safety margins in the integrity of a vessel. These margins have been verified experimentally. The phenomenon of pressurized thermal shock becomes important as plants get older. As a plant gets older, neutron irradiation causes the temperature below which the reactor becomes brittle to increase. Under an extreme set of conditions, it is possible that an undetected pre-existing crack, or crack-like flaw, may propagate through the wall of the vessel.

This is, however, not a new concern which has taken the nuclear industry by surprise. The phenomenon of metal embrittlement has been known since the beginnings of nuclear development. Samples of reactor vessel material are placed in the reactor when it starts operation and checked to monitor this phenomenon. It was by this careful monitoring process that the effect of copper in the metal was observed and low copper materials for reactor vessels have been specified since 1972; therefore, only older reactors are potentially affected. Another misconception is the idea that the reactor vessel could "shatter" or "crumble". While this is a colorful description, it is highly inaccurate. If cold water is poured into a hot reactor vessel, nothing would happen immediately and as the reactor vessel cools, the metal may or may not after 10 minutes to an hour or more lose some of its ductility and become brittle. There then can be a question whether an existing crack on the inner surface of the vessel might grow and penetrate the entire eight inches of steel wall.

In December, 1981, the Westinghouse Owners Group submitted a "Summary Report on Reactor Vessel Integrity for Westinghouse Operating Plants" to the NCR. This study made a conservative assessment of reactor vessel integrity for selected severe pressurized thermal shock events. For all plants, the results demonstrated that no immediate reactor vessel integrity concerns existed, and that, in general, all of

the plants could continue operation for a number of years without violating reactor vessel integrity acceptance criteria.

These studies were extended by the Westinghouse Owners Group and reported to the NRC in May, 1982. The May 1982 report represented a comprehensive review of potential pressurized thermal shock events and possible mitigating actions. Probabilistic techniques were applied to estimate the likelihood that a reactor vessel might be challenged by pressurized thermal shock. The results reaffirmed prior conclusions -- there are no near-term safety concerns on operating Westinghouse nuclear plants due to pressurized thermal shock.

The NRC draft report of September 13, 1982 proposes a screening criterion to determine when detailed plant-specific evaluations would be needed to judge future acceptability of a particular reactor vessel. The NRC made an initial assessment of all domestic plants and found that none would violate the proposed screening criterion until at least 1988. The NRC further proposes to require the utilities owning nuclear plants to submit their proposed plan of action at least three years before their vessel would violate the screening criterion. This would ensure that detailed evaluations are available in time to permit any actions necessary to safety on an orderly schedule.

In testimony before the Advisory Committee on Reactor Safeguards, the Westinghouse Owners Group endorsed the purpose and general methodology of the proposed NRC criterion, but argued that a sound technical basis exists to justify a less conservative criterion. Nevertheless, the W.O.G. supports adoption of the NRC criterion in order to get on with the next phase--the plant-specific evaluations for some of the older operating plants. The pressurized thermal shock issue does not apply, as pointed out earlier, to many nuclear plants in operation or under construction.

For plants where further action will be needed before the end of plant life, a range of actions are available. The action appropriate to a particular plant depends upon the plant. Possible actions include:

A. Perform detailed evaluations specific to the particular plants of concern. These evaluations would include assessment of severe cooldown accidents and vessel material properties applied to fracture mechanics calculations. Existing analyses have been performed to cover groups or classes of plants and are intentionally made

conservative to include the limiting conditions found within the group of plants. The conservative generic analyses are valuable to develop the state of knowledge and identify which plants require closer scrutiny, but tend to give an overly pessimistic result for any particular plant.

B. Improve procedures and operator training which can reduce the likelihood of a severe cooldown accident. This action can be enhanced by improved instrumentation and control equipment.

C. Heat the water storage systems to avoid injecting very cold water into the reactor vessel. This has already been done on one plant.

D. Reduce the rate of neutron irradiation of the reactor vessel by repositioning the fuel. Most utilities either have taken such action or have announced plans to do so. It involves loading older fuel assemblies at the outside of the core. These leading patterns, which typically reduce the rate of irradiation by approximately 50%, do not reduce the plant power capability and also generally tend to reduce fuel costs by making more efficient use of fuel. Changes in the core loading pattern are done at annual refuelings.

E. Improve in-service inspection to more accurately characterize any flaws existing within NRC regulatory acceptance limits (ASME Code).

F. Anneal the reactor vessel in place. This means heating the reactor vessel to approximately 850 degrees Fahrenheit, holding it at the temperature for a few days, and cooling it under controlled conditions. Theoretically, annealing would restore the reactor vessel materials to approximately the condition they were in when the vessel was new. The practicality of annealing is still under study. The process appears to be difficult, expensive, and may require a long outage.

Pressurized thermal shock is a valid issue that merits continued attention, but one that does not, and will not, represent a safety hazard to the public. Practical solutions exist, and can be implemented as needed. Systematic programs exist to ensure that they will be implemented in an orderly fashion where and when required. This represents a continuation of industry practice over the past 20 years.

Psychology of Risk

No constructive dialogue on nuclear safety can take place without first considering the social and

psychological environment in which nuclear power exists. Radiation is clearly misunderstood and considered mysterious by the public. It is unfortunate that, while very infinitesimal amounts of radiation can be measured with simple scientific instruments, ionizing radiation cannot be detected by the normal human senses. The fallacious link between nuclear bombs and nuclear reactors must also be considered. After decades of commercial nuclear power, about 40% of the public still erroneously believes that a nuclear reactor can explode like a nuclear bomb. Dr. Robert L. Dupont, M.D., has written about the nuclear phobia. Some of this nuclear phobia is because nuclear power is so new. Fire is still very dangerous causing thousands of deaths each year, but the human race has gotten used to fire even though very few people understand the chemistry and physics of fire. Some of the problems are due to the difference seen in voluntary risks such as smoking and automobile driving and less voluntary risks like flying, where we depend on unknown pilots and mechanics, and nuclear power, where we depend on government and the utilities to tell the public how much radiation has been measured.

Nuclear fear is the playing out of the "what ifs" of our age. The fact that the effects of radiation can be delayed, as well as immediate, contributes to the "what ifs" syndrome and makes it difficult to place the risks in perspective. There are people whose fear of the potential "what ifs" of the outside world is so severe that they are afraid to leave their homes and require a long period of professional help to put the risks of the outside world in perspective and lead normal lives. In the case of nuclear power, continuation and improvement upon the excellent safety record of nuclear power, as well as providing honest information to help the public be more informed about this technology, will help the public develop a more balanced perspective on the risks of this technology which are small, especially in comparison to its current and future benefits to the nation.

Continuing, and in fact improving upon, the exemplary safety record of nuclear power is one way to improve the public's perception as well as by providing accurate and honest information.

18. Risks of Nuclear Power

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Union of Concerned Scientists

INTRODUCTION

Although the topic of nuclear power still gives rise to heated debates, the technology in the U.S appears, for all intents and purposes, to be dead. The symptoms of its demise are apparent to the most casual observer. Where once twelve to fifteen hundred nuclear plants were forecasted to be operating by the turn of the century, no more than 120 are now anticipated. Since 1972, 98 nuclear power plants have been cancelled, 20 of these since President Reagan--an ardent nuclear supporter--took office. Fourteen plants have been cancelled in the first nine months of 1982. No new plants have been ordered since 1978, and none are expected for the foreseeable future.

New nuclear power plants are no longer economic compared with either new coal plants or with conservation investments. This stems from their safety problems, poor reliability, and rapid escalation of construction costs.

EVALUATING THE RISKS: DEALING WITH UNCERTAINTY

Most treatises comparing the risks of nuclear power with coal are written by nuclear supporters and generally dwell at length on the relatively inconsequential risks of the routine aspects of the nuclear fuel cycle while virtually ignoring the hazards that are considered most important by nuclear critics. Thus the day-to-day impacts of mining, processing, transporting, and the burning of coal and uranium are compared in great detail, leading to the conclusion that, relative to uranium, coal is a dangerous fuel to mine and a dirty fuel to burn. I would not disagree with this conclusion. Indeed, I would concede that were the routine impacts of the nuclear fuel cycle--exclusive of waste disposal--the only issues of contention, nuclear power would be the lesser of the two evils.

More difficult, but far more important to discuss and quantify, are the risks posed by nuclear power in the three areas of power plant safety, radioactive waste disposal, and nuclear weapons proliferation. It is because of the great potential for public harm in

each of these areas that there is so much concern about nuclear energy. The fact that there is so much debate on these issues reflects the great difficulties of making reliable estimates of risks in the absence of sufficient historical experience. I will limit this discussion to the safety issue.

POWER PLANT SAFETY

When the Atomic Energy Act was amended in 1954 to allow private ownership of nuclear power plants, utilities were unwilling to construct them partly because of the unknown risks posed by accidents. To overcome this obstacle, the Congress passed the Price Anderson Act in 1957. The Act set an absolute (and totally arbitrary) limit of $560 million on the liability of power plant owners and their contractors for damages to the public from a nuclear power plant accident. Sixty million dollars of this limit represented the total pool of private insurance available to utilities at that time. The remaining $500 million of insurance was provided by the federal government at premium rates far below those charged by the private insurance companies for their share of the pool. The effect of the Price Anderson Act was to instantly remove the normal market barriers to a potentially very hazardous activity; the nuclear power era was born.

The Price Anderson Act has been renewed and amended over the years but the $560 million limit still holds today despite quadrupling the size of reactors--with the attendant increase of radioactivity in them--and the decrease in purchasing power of the dollar. (Under the most recent amendments to the Price Anderson Act, the $560 million (in current 1981 dollars) will buy only a third of what it would have in 1957. Moreover, the insurance available from private insurance companies ($160 million in 1982 dollars, $54 million in 1957 dollars) has in fact declined over the past 25 years. Thus, the level of financial protection to the public--measured in constant dollars--has decreased by two-thirds since 1957; the portion of protection provided by private insurance has also decreased, though not by much.

This little bit of history is important primarily because the nuclear industry and its government promoters--first the Atomic Energy Commission (AEC) and later the Department of Energy (DOE) and the Nuclear Regulatory Commission (NRC)--have never been able to make a convincing technical case that nuclear power plants could survive serious accidents. In the

early 1970s the Union of Concerned Scientists (UCS) challenged the AEC's licensing of large new nuclear power plants on the grounds that the Emergency Core Cooling Systems (ECCS) had never been tested under anything like realistic accident conditions. The ECCS are the plumbing systems consisting of sprays, pumps, storage tanks, and injection systems that are designed to flood with water the hot radioactive core of a nuclear power plant if the normal cooling water is lost through a Loss of Coolant Accident (LOCA). UCS also challenged the AEC's computer codes, used to predict ECCS performance during accidents, claiming they were crude and unverified. The conclusion of the hearings held to review the ECCS issue left little doubt that the AEC's case was technically weak and that the performance of critical safety systems during accidents was unknown.

The AEC's response to this predicament was to undertake a two-year long computer based Reactor Safety Study--entitled WASH-1400--to estimate the likelihood and consequences of nuclear accidents. Not surprisingly, WASH-1400 concluded that the risks from nuclear accidents were miniscule.

WASH-1400 was the subject of several subsequent reviews including one sponsored by UCS. These reviews unanimously agreed that the computer model used in the study to predict the frequency of nuclear accidents was incapable of accurately doing so and as a consequence there were great uncertainties in the calculated risks from nuclear accidents. In a policy statement issued in January of 1979, the NRC formally announced that it would no longer use the risk estimates of WASH-1400 in its regulatory or policy decision making on nuclear power.

Though the risk estimates of the Reactor Safety Study are not considered trustworthy, use of them continues by nuclear proponents in attempting to establish the safety of nuclear power plants. Indeed, despite its official renouncement of the estimates contained in WASH-1400, the NRC's own staff continues to use the codes developed in preparing that report both to provide quantitative risk estimates for specific nuclear power plants, and to establish that overall safety goals can be met by the industry as a whole. These so-called Probability Risk Assessments (PRA) have been the subject of severe criticisms by members of the NRC's own safety watchdog, the Advisory Committee on Reactor Safeguards (ACRS). Writing to NRC Chairman Nunzio J. Palladino in September of 1982, Myer Bender and Jeremiah J. Ray, two members of the ACRS, made the following observations:

- "The PRA methodology stems from the Reactor Safety Study, WASH-1400. The well-known 'inscrutability' of the WASH-1400 results were primarily a consequence of the thin and generally unvalidated data base used to establish event probability. These data from WASH-1400 are still being used in PRAs with very little discretion concerning their validity. Hardly any new data are available."
- "Among the most serious deficiencies in the WASH-1400 study was its use of the MARCH Code to show the transport radionuclides, an evaluation basis that has since been shown to be seriously in error. The MARCH Code was not consistent with known physical facts, and it literally described the dispersal of radionuclides in a manner contrary to physical laws."
- "The use of PRA for regulatory purposes is defensible if event sequences and related probabilities are well understood and the consequences to public welfare can be clearly defined. The PRA methodology now in use does not meet these conditions."
- After reviewing a number of specific technical deficiencies in PRA calculations, they concluded: "The foregoing is sufficient to show why PRA studies as currently performed will remain inscrutable and will, at least for the next decade, be little more than a display of logical thought based on essentially arbitrary reliability assumptions." "Without question, the most serious distortion of fact being introduced by the use of PRA is the claim that it can estimate the probability of a core melt. As noted previously, the NRC has not even attempted to define what it means by a 'core melt'." "In truth, the PRAs cannot predict core melt probability." "The claims for PRA concerning its ability to assess public safety risk are little more than a sham that will hide the fact that the basis for safety will always depend upon the judgement of a few individuals."

Dr. David Okrent, another member of the ACRS, delivered a paper in 1980 at an international conference on nuclear safety in which he too questioned the capability of elaborate computer models to accurately predict the likelihood of nuclear accidents.

> When draft WASH-1400 in 1974 came up with an estimate of an overall core melt frequency of about one in 20,000 per reactor year (median value), the Regulatory Staff's first reaction was that the WASH-1400 core melt frequency was too high. Since issuance of the final version of WASH-1400 in 1975

> with the same core melt frequency, a considerable number of things have occurred which tend to support the thesis that the WASH-1400 estimate of the frequency of core melt (or at least core damage severe enough to threaten containment and a major release of radioactive materials) was too low.
>
> ...it appears to be difficult to demonstrate with a high degree of confidence that the frequency of severe core damage or core melt for reactors in operation or under construction is less than about one in a thousand per year. It may be smaller, but it is also conceivable that it is somewhat larger. Also, there are many potential paths to severe core damage or core melt so that it will be difficult to make the frequency of such an accident very much smaller, with a degree of confidence.

It should be noted that with the number of plants soon to be operating in the U.S., a frequency of core melt of one in a thousand reactor-years will correspond to a meltdown occurring every ten years or so.

In the absence of adequate operating experience and with little confidence in Probability Risk Assessments, there is no way of knowing what the actual risks of serious nuclear accidents are. And it is in this context that the failures of the nuclear industry to provide quality control in plant construction and operation and to resolve the many important technical problems affecting plant operation must be viewed.

The industry's problems in maintaining quality control in construction have been cited time and again by the Nuclear Regulatory Commission. The NRC's chairman, Nunzio Palladino, said in a speech last December to the Atomic Industrial Forum:

> Some utilities fall short of protecting their own best interests and meeting the high standards expected for nuclear power. Unfortunately, the poor performers are the ones who impact most adversely on the safety and credibility of the industry. Their deficiencies in quality assurance are inexcusable.

> There have been lapses of many kinds--in design analyses resulting in built-in design errors; in poor construction practices; in falsified documents; in harassment of quality control personnel; and in inadequate training of reactor operators.

NRC Commissioner Gilinsky in May, 1982, also addressing the Atomic Industrial Forum, said of the industry's problems:

> While plants are not being held up by lengthy proceedings, there is the possibility, if not the likelihood, that plants which largely finished will not go into operation on schedule because they have not been built right. One, for example, is stuck with an extensive design reverification program because problems have been discovered in its seismic design. More than one is going through an elaborate and time-consuming process of checking and correcting actual construction because proper quality assurance practices had not been followed. Some have had to halt construction to straighten themselves out; another is dead in the water because the architect-engineer was replaced; and so on. And it is not outside the realm of possibility that some of these reactors may not operate at all.

Poor quality control in power plant construction is a major factor in plant delay and cost overruns, and therefore is important in the decline of the economic viability of the nuclear industry. Improper plant construction also has important safety implications and could lead to the shutdown of the industry altogether in the event of another accident as serious as that at Three Mile Island.

Perhaps as important as poor quality control in new construction are the many reliability and safety problems at existing plants. The list of unresolved safety problems is long, and was recently catalogued for the now defunct President's Nuclear Safety Oversight Committee by the Reactor Safety Research Group. The members of the Research Review Group were drawn from industry, academia, and the national labs. The

study group identified "...a number of issues that urgently need research but on which no significant research is being done."

The most important needs, in the view of the Review Group include:

- A major effort to develop and evaluate improved or alternative approaches to more reliable shutdown heat removal systems, for both reactor vessel and the containment,
- A program to develop and evaluate methods of providing more reliable electric station power, both AC and DC,
- A program to examine the relative safety merits of rigid versus flexible seismic design of piping,
- A program to develop valves that are more reliable under both normal and abnormal operating conditions,
- A comprehensive program to develop and demonstrate primary system decontamination techniques applicable to light water reactors (LWRs),
- A program to develop a computational capability to study LWR behavior in real time, or faster, through a wide range of severe transients including accidents involving extensive core damage,
- Programs to determine the mode and likelihood of severe damage by water hammer, and
- Studies to develop design measures to protect against sabotage by an insider while not compromising safety in other respects.

It is truly remarkable that, 25 years into the age of nuclear power, with the design of more than 100 nuclear power plants fixed in concrete and steel, such a list of urgently needed safety research exists. The existence of these problems, however, goes far to explain why nuclear power is terminally ill and why it would take extraordinary measures far beyond those proposed by the Reagan Administration to save it.

Two safety issues of especially great concern are steam generator deterioration and reactor vessel embrittlement. Steam generators are huge steel structures containing thousands of long thin tubes through which the water from the reactor vessel passes. Steam generators have developed a number of serious problems of tube deterioration over the years; generators have had to be replaced at a number of plants including the two Surry plants in Virginia and the two Turkey Point plants in Florida. The failure of a steam generator at the Ginna plant in New York in January, 1982 led to the plant's being out of service for 5 months. Replacing steam generators can cost hundreds of millions of dollars and their failure

represents large financial and safety risks for beleaguered utilities. Although the NRC stated in 1978 that the problems of steam generators would be resolved by the winter of 1979, by January 1982 none of the specific recommendations for ensuring that accidents could be controlled was yet implemented. And the steam generators in plants under construction are similar in design to those in existing plants.

The problem of embrittlement also affects pressurized water reactors. The steel reactor vessel in a PWR is typically 15 feet in diameter, 40 to 50 feet high, and has walls 8 inches thick. Below a certain transition temperature, typically 0 to 40 degrees F in a new reactor, the vessel is subject to rupture if it is stressed too highly. Above this temperature the vessel can withstand much higher stress without failing. To prevent excessive thermal stresses the heat-up and cool-down rates for PWRs are limited to less than 100 degrees per hour, and pressures in the vessel are kept quite low when the vessel is cold. Unfortunately, during an accident there may be little or no control over the relationship between temperature and pressure. Making matters worse, as the vessel is subject to neutron irradiation during normal operation, this so-called nil-ductility transition temperature rises, and has reached over 250 degrees F in some reactors. During a loss of coolant accident the ECCS pumps great quantities of relatively cold water into the reactor vessel. Moreover, as a result of the TMI accident, the operators have been trained to keep ECCS on, which may quickly raise the pressure of the vessel. This combination of rapid cooling of the vessel and rapidly rising pressure could lead to a rupture of the reactor vessel, an accident with which no plant is designed to cope. The result is that many nuclear plants may reach unacceptably high transition temperatures within 10 to 20 years of beginning operation. At present no technical fix has yet been identified to deal with this problem.

There are other problems that still remain unsolved. The changes in fire protection regulations resulting from the Browns Ferry fire will not be fully implemented until 1984, nine years after the fire. And two key changes identified after the TMI accident--adding water level indicators and vents to the cooling system to rid it of steam and gas bubbles--have yet to be implemented.

SUMMARY

Nuclear power plants today are subject to numerous unresolved safety and reliability problems. The

industry is painfully aware of problems as it attempts to cope with deteriorating steam generators, aging reactor vessels, and inadequate quality control in plant construction and operation. Were it not for the crutch of federal insurance subsidies and arbitrary limits on liability, the nuclear industry never would have built nuclear plants as rapidly or as large as they have. The message of the period since the Three Mile Island accident is simple: the utilities have now discovered that they and their stockholders still bear risks from owning nuclear plants, the enormous costs of losing a reactor and cleaning up the site. Safety risks, reflected as economic risks, have had the last word on the viability of nuclear energy.

19. Nuclear Power: Opportunities and Constraints

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This paper will briefly present the opportunities and constraints of nuclear power from the electric utility's perspective. First, let us examine the opportunities of nuclear power for electrical generation, which have been demonstrated by our experience at Commonwealth Edison.

In terms of economics, nuclear power is the most economical means we have to produce electricity. For example, in 1981, the cost of electricity produced by Edison's six large nuclear power plants was one-half the cost of producing power from our coal-fired plants and less than one-quarter the cost of power from our large oil-fired plants. In 1981, our nuclear power plants produced 27 billion kilowatt-hours, or 45 percent of our system's generation. As a result, our customers saved over $500 million in pass-through fuel costs as compared with coal, and about $2.0 billion if the same amount of power had been produced with oil.

If Edison were to order more nuclear plants today for operation in early 1990, our studies show that compared with coal, the electricity produced would cost from 10 to 20 percent less during the plant's first ten years of service, or from 21 to 38 percent less during a 25-year period, depending on how future fuel costs escalate.

In terms of safety, the safety record of nuclear power plants has certainly been remarkable. In over 20 years and more than 550 reactor years of United States commercial nuclear power plant activities, there has never been a nuclear accident which has killed or injured any member of the public or the people working inside nuclear power plants. Other countries have amassed a total of 1300 reactor years of experience, and the Nuclear Navy has logged over 1900 reactor years of experience without a major nuclear accident. This safety record is unparalleled in any other industry and is still intact even in view of the Three Mile Island accident. This is not to say that no one will ever be killed by radiation, but the record that has been compiled over the last 20 years demonstrates the safety of nuclear power as a means of electrical generation.

In the area of operating reliability, our nuclear units have performed better than our coal-fired units. The availability of our six large nuclear plants was

77% last year compared to 66% for our six large coal-fired plants.

Last year, during our peak load period from June 1 to September 1, our nuclear stations were available for service 97.8% of the time -- a new reliability record for the Company.

There are many constraints to nuclear power. I will review those constraints with the greatest impact. The two most significant constraints are escalating nuclear regulatory requirements and reduced public confidence in nuclear power.

Increased nuclear regulations have lengthened the schedules and escalated the costs of plants under construction. Construction schedules in the U.S. run over twice as long as those in Japan, and there are continual plant modifications stemming from changing requirements. These add 50 percent or more to the capital cost of nuclear capacity.

Additionally, reduced public confidence is becoming a constraint to nuclear power. Since the Three Mile Island accident, nuclear power is being judged by a higher standard than the competing technologies. This public perception of nuclear power, to some extent, is influenced by the media. This was demonstrated by a study some journalism students made of the New York Times about a year ago. They found that there were 12,000 fatal industrial accidents in 1980 and 50 stories about them, or one story for every 240 fatalities. There were 4,500 cases of suffocation resulting in 25 stories, or one story for every 800 fatalities. There were 50,000 Americans killed on the highways, which resulted in 120 stories about fatal car accidents, or one report for every 417 people killed.

Now, when we look at nuclear power, there were zero fatalities from nuclear radiation. Not one single death. Yet, that year, the New York Times managed somehow to run 200 stories on the possibility of radiation deaths.

The media will continue to make a big production of nuclear stories; therefore, in order to maintain public confidence, we simply must lower the frequency of significant events to the absolute minimum. The Institute of Nuclear Power Operations, formed by the industry after Three Mile Island, will have a major impact in this area by assuring that all nuclear plants meet standards of excellence.

In conclusion, the opportunities of nuclear power for electrical generation are great. We must overcome the constraints, because nuclear power will be needed in the energy mix of this country in the foreseeable future.

20. Are Nuclear Power Plants Safe?

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Is the current generation of nuclear power plants safe enough? I am tempted to respond by asking, "For whom -- the utility stockholders or the public who lives near them?" The stockholders in a utility that has an accident as serious as that at Three Mile Island-2 will lose a great deal of money. However, for the people who live near nuclear plants, I am convinced that the reactors are safe.

Let me get more personal about assessing their safety. I have spent a good deal of time in the last six years reviewing and advising the NRC on matters of the safety of the country's nuclear power reactors. Also, I was raised and graduated from high school in Stillman Valley, Illinois, a village within sight of Commonwealth's new Byron plant. My family has lived in the community for over fifty years. I am firmly convinced that the nuclear plant will not represent a significant risk to my friends and family there. You may feel uneasy about risks from something as new and powerful as a nuclear reactor, or you may not, but after looking at them fairly closely I do not.

Let me turn now to potential safety questions that are more technical, and about which I have some expertise. Two potential problems that have been in the news lately are steam generator degradation, and the so-called pressurized thermal shock of pressure vessels.

First the steam generators. A steam generator is somewhat like the tea kettle my mother used to have on the back of her cookstove. You put water into it, some of the water evaporated as steam, and the impurities collected inside the kettle as hard deposits. In a PWR the steam generator evaporates its feedwater to cool the reactor and to make steam for the turbine. Any impurities that get into the feedwater are concentrated there. Impurities that are noncorrosive at low concentrations often become corrosive at high concentrations. Ultimately this corrosion can lead to the development of small leaks in the steam generator tubing so that the radioactive water from the reactor leaks into the steam generator which leads to the turbine. As a result, the operators must shut down the system and fix the leak. This does not constitute a significant risk to the neighbors, but it has been one of the larger causes of down time for the plants.

Consequently, it is clearly in the interest of the utilities to avoid this problem.

Unfortunately, it has taken the utilities some time to learn how to control these leaks into the secondary system. Some steam generators have corroded so badly that they have had to be replaced well before their design life was reached. This is expensive and exposes a lot of workers to radiation. However, it is much more an issue of economics than one of public safety. The utilities have funded research programs to learn how to cope with these problems. To date, real progress has been reported by The Elective Board Research Institute (EBRI).

The pressurized thermal shock issue is quite different. The kind of reactor accidents that pose the greatest risk to the public are those in which the ability to remove the decay heat from the core is lost. This can lead to a melt down of the core and the release of its radioactivity into the containment vessel and possibly into the environment around the plant. This is the so-called core melt accident and most of the safety systems in a nuclear plant are there to prevent it. An essential feature in preventing this accident is the integrity of the pressure vessel. The vessel has been designed and built so conservatively that its rupture has been considered to be incredible. However, since the early generations of pressure vessels were built people have learned that copper impurities at the level of only a few tenths of a percent in the vessel will accelerate the rate at which this steel loses its toughness, or more precisely raises the minimum temperature at which it keeps its toughness. Thus, one can think of a sequence of events in which cold water is pumped into the vessel at high pressure to keep the core covered with water. If in addition there is a preexisting crack in the middle of the vessel where the irradiation was greatest, one might open the crack and push it all the way through the wall leading to a situation in which it is impossible to keep the core cooled. The problem is that, if the accident is to occur, several very unlikely events must coincide:

1. The vessel has to be an old one which was made with an exceptional amount of copper impurity concentrated in one place.
2. The plant has to be in an upset condition due to some equipment failure, and the operator has to be doing the wrong thing because he is getting misinformation or is confused.
3. There has to be a significant crack existing in just the right place near the core midplane.

These are all very unlikely events, but not impossible. Thus you can, and do, have honest differences of opinion between the regulators dreaming up all the ways things could go wrong and the utilities who are convinced that the regulator's assumptions are grossly over-conservative. The ACRS has looked closely at the problem and agrees with the NRC staff that even in the few plants with the most sensitive pressure vessels the irradiation accumulated to date does not put the plants at risk, and will not for several years. Whether or not something is drastic, like annealing the pressure vessel, must be done to keep these plants operating for the projected life of 40 years is still to be decided.

21. Illinois' Nuclear-Preparedness Program

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Director
Illinois Energy Disaster Services Agency

While the topic of coal and nuclear power would be well received in any industrialized and heavily populated state, in Illinois it is especially appropriate. Illinois leads the nation in the production of nuclear power. It is extremely important, therefore, that Illinois accept a leadership role along with the nuclear industry in developing a well-outlined and organized program for emergency preparedness. Nuclear production and emergency preparedness -- one cannot nor should not exist without the other.

In Illinois, the nuclear preparedness plan is referred to as the IPRA, the Illinois Plan for Radiological Accidents. The Illinois Emergency Services and Disaster Agency (ESDA), as lead agency for Illinois, is committed to safeguarding the health, safety and well-being of the Illinois citizens and protecting their property. ESDA has coordinated the efforts and resources of all state agencies and has developed a plan to protect the public in the event of an accident at a nuclear power facility.

The IPRA pre-assigns the duties and responsibilities of the operating utility, all federal, state and local agencies, law enforcement groups, and support organizations like the American Red Cross and Salvation Army so that each could act quickly, efficiently and responsibly if a need arises. In less sophisticated terms, the IPRA is the blueprint for the operation and cooperation between every individual or group responding to a nuclear emergency. While its main objective is to protect the citizens residing or working near nuclear power facilities, it also provides the systematic allocation of resources and personnel in response to a nuclear incident.

At the present time the IPRA consists of the General Plan, Volume I, and four site-specific preparedness plans. Volumes 2, 3, 4 and 5 cover the facilities at Dresden, LaSalle, Quad Cities and Zion respectively. They specifically concentrate on the citizens residing or working in the Emergency Planning Zone (EPZ) which is a ten-mile radius surrounding the nuclear power plant. This is the area which would be affected by a plume exposure should radioactive material actually be released. Additional volumes will be added for Byron, Braidwood and Clinton as their construction nears completion.

Some of the elements which compose the IPRA include:

1) the initial notification and warning,
2) the assessment of the radiological accident,
3) the protective actions such as shelter-in-place, evacuation, traffic control, and the administration of radioprotective drugs to name only a few,
4) parallel actions which include medical services, exposure control, social services, law enforcement and re-entry, and
5) public information and the media.

This final component is vital to the overall effectiveness and successful implementation of the previous components. Keeping the public informed of the nature and the consequences of a nuclear incident, both during and after such an incident, is of utmost importance. It is also one of the things which is most difficult to administer because, in addition to the information being released by the state spokesperson, there are numerous other sources of press releases--utilities, local and federal government agencies, and contiguous states.

The Governor or his designee shall be the public information spokesperson for the State of Illinois. His two primary sources of information will be from ESDA's Emergency Operating Center and from the Illinois Department of Nuclear Safety (DNS) who will supply information from the field and provide analysis and assessment data from Springfield. The IPRA also provides for frequent press briefings and a rumor control network using the dedicated phone lines (NARS) which provide security and the uninterrupted flow of plant-status messages. The NARS reporting network is tested daily by the State ESDA Communications Center.

The primary sources from which the news media will receive their information include the News Conference Room in the State Capitol and the Joint Public Information Center located near the affected plant.

In order that ESDA and the Department of Nuclear Safety (DNS) do not duplicate one another's responsibility, the operational response and overall coordination are handled by ESDA while the technical functions are performed or directed by DNS.

Developing and writing a plan, as just described, only partially fulfills the mission which has been assigned to ESDA. The more crucial aspect in a nuclear preparedness program is not having a plan but more importantly having a plan that works--one that has been taken off the shelf and implemented in trial

situations simulating a nuclear power plant incident. *This cannot be stressed enough. It is absolutely* necessary to practice, to drill, to exercise each site-specific IPRA to see how all the parts come together. Eight drills have been executed in Illinois, and another is currently being prepared to be held in Zion.

Under the guidance of the Nuclear Regulatory Commission and the Federal Emergency Management Agency, it has been mandated by Congress that each site-specific IPRA be exercised annually. This kind of requirement in a State with 4 nuclear power plants on line and 3 more coming on line within the next 2 years keeps the ESDA staff in a continuous state of preparation--thoroughly revising and updating the plan, meeting with local officials and support groups, training 400 to 500 volunteers, and drafting a scenario. These activities take hours, weeks, even months to complete.

The exercise cycle for 1982 began in April. The LaSalle nuclear preparedness exercise was a two day affair involving a full-scale test of the utility, all the State agencies, emergency response officials and organizations from LaSalle County and four municipalities. This exercise also demonstrated the successful evacuation of 150 Boy Scouts from the Illini State Park to Seneca.

In late June the seventh State exercise was conducted involving three counties and eight municipalities. While part of the ESDA staff was gearing up for the Dresden Station exercise near Morris, Illinois, the other part was covering the day to day incidents and the recovery efforts in tornado-ravaged Marion. In addition to the Dresden exercise being the first nightime drill in the Midwest, it also was the first in the nation in which handicapped persons including paraplegics, blind and bedridden individuals were acutally evacuated using lift vans and ambulances. Fourteen FEMA observers critiqued the exercise and gave Illinois an overall rating of "adequate". Federal critiques are either "adequate or "inadequate."

A recent exercise took place on August 24, 1982 at the Quad Cities Nuclear Station. Similar amounts of preparation preceded the actual drill; however that day because the scenario called for an eastwardly wind, the downwind sectors requring evacuation up to two miles fell upon our counterparts across the river in Iowa.

The State of Illinois has taken its role of leadership in nuclear preparedness seriously. Even after repeated drills, Illinois cannot afford to

become complacent. The State cannot afford to be satisfied with a plan that looks good on paper and gets high marks in a simulated situation. The State must continue to interact with the nuclear industry and the local governments and residents so that each and every individual is well informed and knows what to do in case of a nuclear station emergency. Brochures with this title, "What to Do in Case of a Nuclear Station Emergency", are distributed annually to residents within ten miles of a nuclear facility.

When one considers that approximately one-third of our State's electircal generating power is supplied by nuclear reactors, it is easy to understand why nuclear energy is something we must live with, adapt to, and prepare for in the event of an accident that could affect the public.

In the three years that have passed since the incident at Three Mile Island, state emergency and disaster agencies across the country have taken on an overt awareness of the need for a nuclear preparedness program. The confusion, the indecision and duplication at Three Mile Island was apparent. Illinois along with other states with nuclear facilties, learned a lesson and knew that they had to correct their own planning efforts. Since the planning process is dynamic and on-going, success can only be measured in minute achievements rather than total accomplishments.

V

NEW TECHNOLOGIES

22. The Synthetic-Fuels Industry: A Future Outlook

Edward S. Miller
Vice President - Finance
United States Synthetic Fuels Corporation

Energy, perhaps more than any other commodity, affects and to a large degree controls the well-being and progress of the individual, the community, and the nation. Yet for all its influence on our lives, energy was one of the most misunderstood and mishandled national policy issues of the seventies. For almost a decade the U.S. based its energy policies on reaction and political rhetoric, veering from periods of panic and impossible promises to periods of indulgence and indifference.

The two oil shocks of the 1970s cost the Western industrial nations severely in economic terms. One recent analysis* estimates the cost at more than one trillion dollars in lost economic growth, inflation and unemployment in OECD countries. In the U.S. we continue to use oil faster than we are finding it. In September 1982 the Department of Energy revised its forecast of the quantity of oil the U.S. will import at the end of the century to 4.6 million barrels per day, up from a previous estimate of 1.2 million. Import dependence will then be 38% of oil needs, about the same as today.

Public attitudes about energy change dramatically. Just a few years ago we were in a nationally-proclaimed "energy crisis." Oil prices had jumped, contributing to serious inflation and slowing economic growth. Some forecasters projected prices of $100 a barrel before the end of the eighties. There were predictions that supplies of conventional oil and gas were running out, that the power of OPEC was absolute, and that we'd better start changing our way of life. Now, two years later, these attitudes have changed.

The United States Synthetic Fuels Corporation was created at the height of the oil shock by the Energy Security Act in June 1980. It is "a federal entity of limited duration formed to provide financial assistance to synthetic fuel projects." Currently, the Synfuels Corporation is alive and well, and working toward its goals. Contrary to some press reports, it did not expire when Exxon withdrew from the Colony oil shale project.

*IEA: Energy Policies and Programs of the IEA Countries, 1981 Review, Paris, 1982.

Synthetic fuels are destined to play a role in America's energy future. They will eventually be produced from domestic resources that are found in great abundance. Only 10% of our fossil energy reserves are conventional oil and gas, the balance being in solid forms. Once these can be converted to liquids and gases economically and cleanly, they will be capable of meeting our energy needs for many decades.

The country needs the proven commercial capability (not merely research and pilot plants) to produce synthetics. Government, working in close cooperation with the private sector, can stimulate development of this capability much sooner than the marketplace alone can.

Congress recognized the indispensable talents of industry--technical, managerial and financial. One of the Act's most important philosophical underpinnings is that the central role in developing a synfuels industry lies with private enterprise, not with the Corporation. Industry is expected to make the business judgments on which resources to develop, which technologies to employ, where to locate plants and what products to produce.

The rationale for a government stimulus to synfuels is both strategic and economic. If it can be established that synthetics are producible at some constant dollar value -- say $40 per barrel or even $50 dollars -- it will, in effect, put a lid on arbitrary price increases by exporting nations. The latest Energy Department study forecasts oil prices of $62 per barrel in 2000.

Congress gave the Corporation several guidelines:

-- Production goals: A synthetic capacity equivalent to at least 500,000 bpd by 1987 and 2,000,000 bpd by 1992.
-- Diversity goals: To develop a "portfolio" of projects using several processes for each resource.
-- Public benefit guidelines, such as learning from the initial plants, exercising environmental care, and fostering competition in the new industry.

The tools Congress provided to do the job are the Energy Security Reserve Fund and the power to grant various forms of financial assistance, of which the most important are loan guarantees and price guarantees. SFC can guarantee U.S. government repayment of loans aggregating up to 75% of the cost of a project. SFC price guarantees can provide payments if the market price of a synthetic fuel drops below a pre-

agreed projection, up to a fixed amount over a fixed period of years.

The Corporation expects to have about $15 billion with which to make future assistance awards. The final $6.2 billion was made available on June 30, 1982.

A permanent Board of Directors was not confirmed and seated until October 1981, so the Corporation has been fully functional for only about a year. In February, 1982 President Reagan declared the Corporation operational. The present Board and management are dedicated to bringing on line a moderate number of economically viable plants, through careful selection and with all deliberate speed, so that the ultimate outlay of government funds will be no higher than necessary.

As of today, October 1982 the Corporation has not made any awards of assistance, but SFC is authorized to negotiate assistance for 12 projects that have passed reviews. SFC is also monitoring the Union Oil shale project which transferred from DOE. Some accuse the Corporation of going too slowly, or of being too rigorously selective. But, it is essential to proceed in an orderly and responsible way. If it takes a little more time at the beginning, there will be fewer problems later. SFC's job is to assure that its assistance encourages and supplements but does not displace private capital investment otherwise available. In picking projects it must conduct careful examination that would be done by any prudent lender.

The corporation is, of course, also well aware of the other side of this equation -- of the substantial risk assumed by those who invest in synthetic fuels. One potential sponsor, for example, said he liked to gamble. "However," he said, "I prefer the horse races -- the air is fresher, the odds are better and I can pick my own company." There is no question that investment in synthetic fuels today is a gamble that turns off risk-averse managements. But the Synthetic Fuels Corporation is in business to try to even up the odds. Some negatives to synfuels are high initial capital costs and numerous technical and economic risks. Caught in today's recession and facing many uncertainties, even the strongest industry sponsors have a hard time justifying investment in synfuels in terms of the near-term bottom line. Business managers need at least contingent assurances against uncertainties before they can invest in pioneer plants. The Corporation is prepared to provide such backing for strong projects with committed management.

The scorecard to date is as follows: Two general solicitations for projects have been held. About

80 projects were submitted, of which today 13 remain. The others failed to meet the maturity or strength tests that are applied to every proposal. The 13 include 5 coal projects, of which one is direct liquefaction, 3 indirect liquefaction, and one gasification. The remainder comprise one oil shale, one peat liquefaction, one heavy oil and 5 tar sands projects. A third general solicitation is in progress, under which new project submittals will be accepted through January 10, 1983.

Perhaps the greatest problem so far has been the lack of sponsorship by strong corporations, those with the money and know-how to back major projects. In many cases, good synfuels concepts have been submitted by companies willing and able to carry only a portion of the project, who are in need of partners to form joint ventures.

The Board wishes to encourage experienced and substantial corporations to become actively involved in, and financially committed to, some of the mature projects now under study or expected to be submitted. These efforts have been called Project Outreach, and invite such companies to come in and talk, one on one, about any and all ideas. Procedures have been changed to accelerate the start of negotiations for projects that have passed the maturity tests.

The Corporation is required to develop and submit to Congress by June 30, 1984 a comprehensive strategy for achieving national synfuels production goals. It will include the findings from facilities sponsored by the Corporation and such issues as economic and technical feasibility and environmental effects. The strategy report will also recommend any specific mix of technologies and resource types proposed to be supported in developing the industry after approval of the strategy.

SFC has an outstanding Board of Directors, a solid consistent program, and the support of the Administration and Congress. It is determined to help private industry get some synfuel plants built and then to let the market take its course. Though the lead is with private enterprise, the Corporation has many resources and is determined to use them to help bring an industry on line.

There is a buzzword in the Corporation, "programmatic". Programmatically, the Board has resolved to emphasize America's most abundant energy resources. It determined that up to $10 billion of our authority should be alloted: $6 billion to coal, $3 billion to oil shale, and $1 billion to tar sands and heavy oil. The remaining one-third of the Corporation's obligational authority is not yet earmarked. The allot-

ments are roughly in proportion to the magnitude of domestic solid fossil fuel resources.

Tar sands and heavy oil offer the potential for quick commercial production although their longer term contribution will be modest. Output of 500,000 pbd may be possible within this decade at relatively low cost. Typically the projects are small, $50 to $100 million, so a large number can be supported.

Coal projects, particularly those in the eastern half of the nation, appear to require more assistance on average because of higher unit costs, larger minimum economic size and greater technological risk. Yet production of synfuels from coal is essential because coal is the largest and most diverse resource base, and it can utilize a wide range of technologies.

Also, coal is less likely to be constrained by siting problems in the event of a major scale-up of the industry. However, the higher cost of coal projects may limit the number that can be assisted. Several such projects are needed to build experience for long-term utilization of this enormous resource, hence the $6 billion allocation. An initial set of projects probably ought to include a western subbituminous project to complement the Great Plains lignite project, which is monitored by the DOE, as well as two eastern coal projects. Should such coal projects require $2 billion of support on average, the allocation can support three projects.

This, then, is the mandate and the program at the Synthetic Fuels Corporation. SFC is working with and through the private sector to develop and bring on line a diverse set of commercial-size synthetic fuels plants that will give this country the know-how and experienced personnel and infrastructure on which to expand a synfuels industry, when and as the market directs.

The money the Corporation puts at risk in developing synthetic fuels is of direct benefit to the nation. Improving the effective transformation of the vast reserves of solid fossil energy into the liquids and gases, the country gains three important objectives:

- Development of economic and defense security;
- Enhanced economic stability for all the oil consuming countries;
- We signal the oil exporting countries that pricing and export decisions should be reasonable.

23. The Great Plains Coal-Gasification Project: Status Report

John B. Cox
Manager
Planning & Administration
ANG Coal Gasification Company

The Process

The Great Plains coal gasification project is a two billion dollar high BTU gasification project currently under construction in Mercer County, North Dakota. The facility will produce 137 MMSCF per stream day or 125 MMSCF per average day of 970 BTU/CF gas interchangeable with natural gas and is scheduled for full gas production commencing December 1, 1984. The process is briefly described by Figure 1.

The process begins by bringing 14,000 tons/day of sized lignite together with 2850 tons/day of oxygen and 13,650 tons/day of steam into the fixed-bed Lurgi gasifiers.

The gasification plant will utilize the most current Lurgi process technology. Coal is first prepared by crushing to the desired size and by screening to remove the fines. The coal is then introduced into gasifier vessels, where it is dehydrated, devolatilized and gasified by reacting with oxygen and steam. The raw gas produced is a mixture of which carbon monoxide, hydrogen, carbon dioxide and methane are the principal components.

Next, the raw gas is cooled and scrubbed to remove tar, dust, heavy oils and gas liquor. The tars and heavy oils are recovered and the gas liquor is further processed for recovery of phenols and by-product ammonia. Part of the raw gas is then passed through a catalytic shift reactor where the composition is modified to provide a ratio of hydrogen and carbon monoxide more suitable for methanation.

The synthetic gas is then purified by washing with chilled methanol in a Rectisol unit to remove naphtha, carbon dioxide and sulfur compounds. The purified synthetic gas is next methanated in catalytic reactors to convert the carbon monoxide and hydrogen to methane. In the final process steps, the synthetic gas is compressed and dehydrated to achieve a pipeline quality synthetic gas with a minimum heat content of 970 Btu per standard cubic foot. The ash from the coal is cooled, dewatered, and buried in specific areas of the mine.

The hydrocarbon liquids removed from the raw gas stream by cooling are separated and then utilized

PLANT MATERAL BALANCE

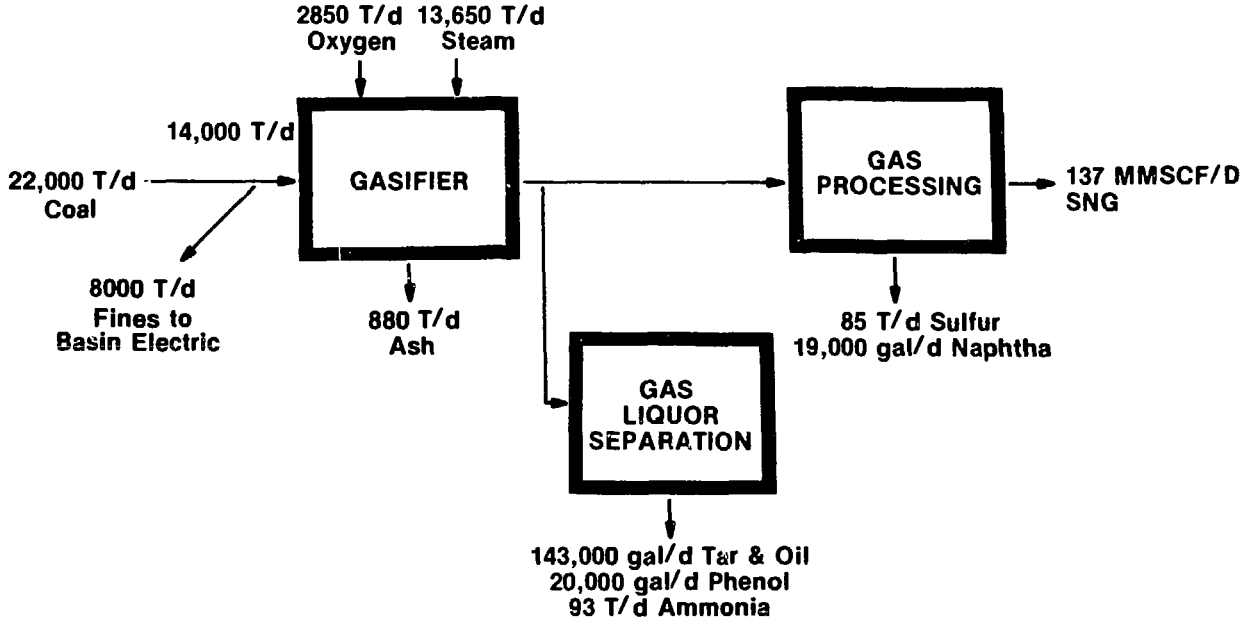

Figure 1

mainly as in-plant fuel. Phenols are extracted and upgraded to be usable as fuel within the plant or sold as chemical feedstocks.

Ammonia in the liquid streams is removed as a by-product. The sulfur removed from the shifted gas is recovered as a byproduct, and the naphtha removed is used as in-plant fuel. A methanol unit which produces methanol from coal gas (for internal plant consumption) is also included in the processing scheme.

The ash handling, coal handling, and cooling water systems are similar in size to those used in a large coal-fired electric power plant. The air separation plant which supplies oxygen for gasification is one of the larger plants of its type in the world. Other utility systems normally found at industrial facilities required to support such process units include: three 500,000 pound per hour stream generation units, a 6,000 gpm water treatment system; a 90 MW electric distribution system; a flare system; tankage; and various waste water treatment systems. The plant contains numerous process and utility compressors and pumps which range from 6,000 to 30,000 horsepower. Electric motor and steam turbine drivers are used to power this equipment.

All of the above processes use equipment which have been proven on a commercial scale. However, the specific processes have not yet been integrated together in one large plant in exactly the same process configuration. While there are two large coal gasification plants operating in South Africa with similar equipment, there is nothing comparable to this plant in the United States.

Great Plains Gasification Associates

The above described plant is being constructed for Great Plains Gasification Associates, which is a consortium of affiliates to five major natural gas transmission companies as shown in Figure 2.

ANG Coal Gasification company reports to Great Plains and has the responsibility for plant design, construction and operations.

The genesis of Great Plains began in the very early 1970's when American Natural Resources, the parent company of one of the present consortium members, became concerned that more natural gas was being consumed each year than was being discovered. Since coal is a far more abundant U.S. energy resource than natural gas and there was little question in 1972 that technology would be available to produce coal

GREAT PLAINS GASIFICATION ASSOCIATES

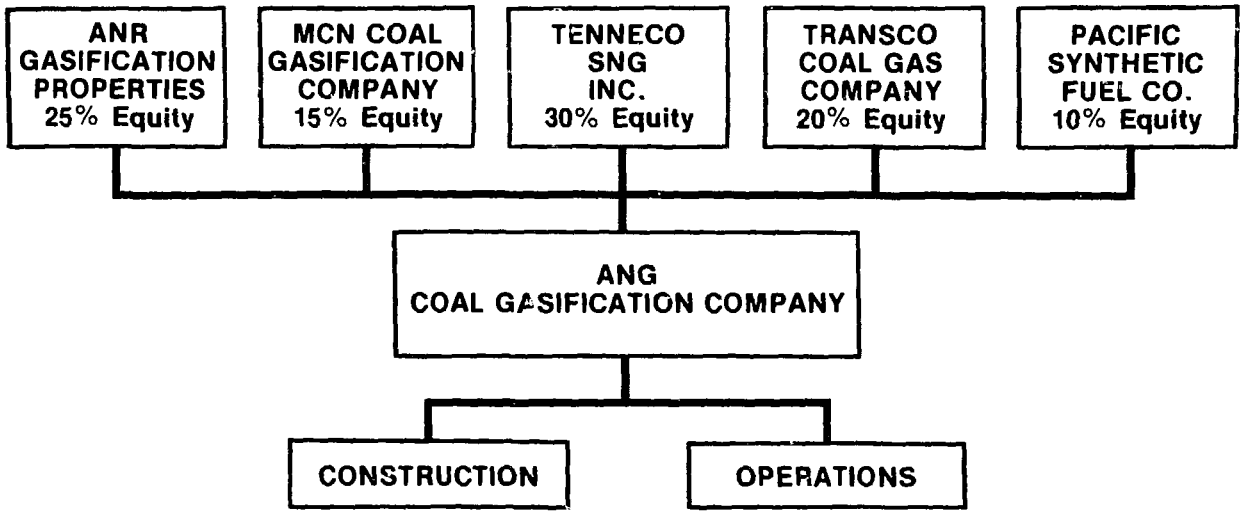

Figure 2

gas interchangeable with natural gas, ANR obtained options to 1.5 billion tons of North Dakota lignite coal reserves. Further coal aquisitions have expanded these reserves to approximately four billion tons.

The coal acquisitions and subsequent project history are described in more detail below:

May, 1972 Coal Options

The lignite coal options were secured in North Dakota because:

- Lignite coal is a highly reactive coal which can be gasified by most gasification technologies.
- Lignite is abundant in North Dakota and was relatively inexpensive to acquire since the only major alternative use is for electrical generating plants operating in a sparsely populated area.
- North Dakota has been encouraging new industrial development and has proved to be a friendly host state for our gasification project.
- The particular location of the coal reserves is near Lake Sakakawea which was formed by a dam on the Missouri River. While coal supplies the carbon needed for coal gasification, water supplies the equally necessary hydrogen requirements. In addition, water is needed for cooling and for process steam.

February, 1973 Water Permit Applications and 1974 Permit Receipt

The 1973 Water Permit applications were made prior to any commitment to a specific coal gasification technology. However, ANR had committed to the proven West German Lurgi technology prior to receipt of a permit and engaged Lurgi for design together with CE-Lummus Company and Kaiser Engineers both for design and construction.

March, 1974 North Dakota Office

In any large new project which can be influenced by politics and local concerns, it is imperative to provide information to all parties concerned. ANR opened a small public relations office in North Dakota prior to substantial project commitments. This office has been of great help in maintaining a friendly attitude in North Dakota and we have had no problems in working with any of the state or local authorities.

July, 1974 Coal Testing

In any coal gasification technology, the reactors have to be designed for the specific coals. North Dakota lignite had never been gasified in significant quantities in any coal gasification reactors, so 12,000 tons of lignite were shipped to an operating Lurgi plant in Sasolburg, South Africa in 1974. The tests were an unqualified success and greatly helped subsequent design efforts. Without these tests, we would have overdesigned several of the process units and, perhaps, underdesigned others.

March, 1975 FPC Application

In March, 1975 application was made to the FPC (now FERC) for a 250 MMCFD plant, which is twice as large as the current plant being constructed. In 1975, it was hoped that both the FPC and the financial community would consider the project similar to construction of a large electrical generating plant which had received regulatory approvals which allowed conventional financial arrangements. This was not to be the case since financing became the central issue for this project and all similar projects. Related issues were:

- No one could predict with certainty how well pioneer coal gasification plants would work.
- Federal regulations were based on laws concerning natural gas rather than synthetic supplies.
- Federal agencies could not provide approvals which would provide financial returns commensurate with project risks.
- The project was too large for any one company to take on all the associated risks. While the technical risks appeared to be long-shot risks, no company could be expected to "bet" their total financial viability on the project outcome, particularly when normal regulatory treatment would only provide a low level return commensurate with the low risks associated with normal pipeline projects.

December, 1975 Loan Guarantee Bill

Because of the above problems, ANR and other companies considered applications for federal loan guarantees. In December, 1975, however, the House voted down one of the first attempts for loan guarantee legislation.

March, 1976 Reduction of Plant Size

In 1976, Congress realized that no synthetic projects were being constructed and there was stronger support for federal loan guarantees. The support wasn't strong enough, however, and the 1976 proposed legislation was defeated by two votes.

March 1977 Initial Partnership

In 1977, ANR's project, like all similar projects, was floundering due to the financing problems. Peoples Energy had a similar project in North Dakota and hoped that success of ANR's project might set a precedent which would enable them to eventually construct their own project. Peoples joined ANR as a 50% partner.

1978, Great Plains Formation

In 1978, the Department of Energy indicated that they would help support the project if it had a wider basis of industry support. Tenneco, Transco and Columbia joined the project and Great Plains was formed. Columbia later withdrew due to legal restrictions and Pacific Lighting recently joined the project as a fifth member of the consortium.

The formation of Great Plains clearly established the project as the lead coal gasification project in the U.S. and preceded innumerable negotiations and hearings relative to Government authorizations, financing methods and gas sales contracts over the next few years.

While the ultimate fate of the project was uncertain, the project sponsors were convinced that the project had a better chance of untangling the government support and financing issues than any similar project. Thus, the project was able to continue with engineering and other tasks while other similar projects were forced to either terminate or severely restrict progress.

July, 1980 Loan Guarantee

In July, 1980 President Carter approved a Conditional Commitment for a loan guarantee exceeding $240 Million. This was intended to give a signal that more government support would be forthcoming so that the project could proceed in an orderly manner. This was necessary since the project sponsors could not bear the risk of rapidly escalating project costs and also could not slow the project down without risking the termination of the project due to numerous actions

required by specific dates in permits and project contracts already in place. August, 1981

It had been hoped that all federal support issues might be settled prior to the end of the Carter Administration. Unfortunately, the issues were too complex to allow this to happen and the Reagan Administration was left with the job of determining the ultimate fate of the project. While there was a fairly well publicized split with the Reagan Administration on the advisability of Loan Guarantees, President Reagan authorized DOE to issue a conditional loan guarantee for up to $2.02 billion in August, 1981.

August, 1981 Construction

Almost simultaneously with authorization of the conditional loan guarantee, full scale construction commenced. This construction effort got off to a very fast start for the following reasons:

ANG had earlier worked out agreements with Basin Electric, a REA electric power cooperative to construct a steam electric generating plant on the same site as the gasification plant. The generating plant would provide power both to the plant and other Basin Electric customers and both projects would share the project water supply system, rail facilities, project roads, certain coal handling facilities, etc. resulting in economic benefits to both projects. Since the Basin project moved into the field well ahead of Great Plains, many of the above facilities were already in place in 1981. In addition, the projeft sponsors had provided funds in 1980 for plant site grading, work on some buildings, piling work, etc.

Finally, the project had negotiated conditional agreements with many equipment vendors and subcontractors prior to August, 1981. While the project was being delayed on a week-to-week basis in mid 1981, there was immediate mobilization of contractors, subcontractors and vendor shops. Within a matter of days, workers assembled on the site and the work force increased to approximately 1000 personnel on the site prior to the Winter of 1981-82. This work force at the plant site has since expanded to over 3,000 as shown in Table 1 which includes home office employees.

Current Status

Where are we now? As noted, construction of plant offsites preceded the August, 1981 financial release, and as shown on the next table, construction is about one quarter completed. Engineering was about 86% complete at the end of August this year and is already winding down. Procurement is well over 60%

complete and most items have been ordered under fixed price contracts which will lock in the final cost impact on the total installed cost of the plant. When all factors impacting plant costs are given a relative weight to one another, the plant is estimated to be over 50 per cent complete today.

TABLE 1
TOTAL GREAT PLAINS
COAL GASIFICATION PROJECT
MANPOWER
AS OF SEPT. 1, 1982

ANG Employees (Home Office & Field)	340
Subcontractor Employees (Direct & Indirect Construction)	555
H. J. Kaiser Employees (Direct & Indirect Construction)	2,600
Lurgi Employees	60
Parsons Employees	35
Kaiser Engineering Employees	240
Lummus Engineering Employees	400
	4,230

8-31-82 PHYSICAL PROGRESS

	SCHEDULED	ACTUAL
ENGINEERING	88.3%	86.1%
PROCUREMENT		
EQUIPMENT	71.7	62.7
COMMODITIES	70.2	64.7
SUBCONTRACTS	82.2	76.8
CONSTRUCTION	27.0	23.8
OVERALL	53.9	49.2

Figure 3 shows our overall construction progress. As shown, we are about one month behind schedule, but we are currently catching up and should soon be back on schedule. The schedule slippage was caused by a number of problems including a cold winter.

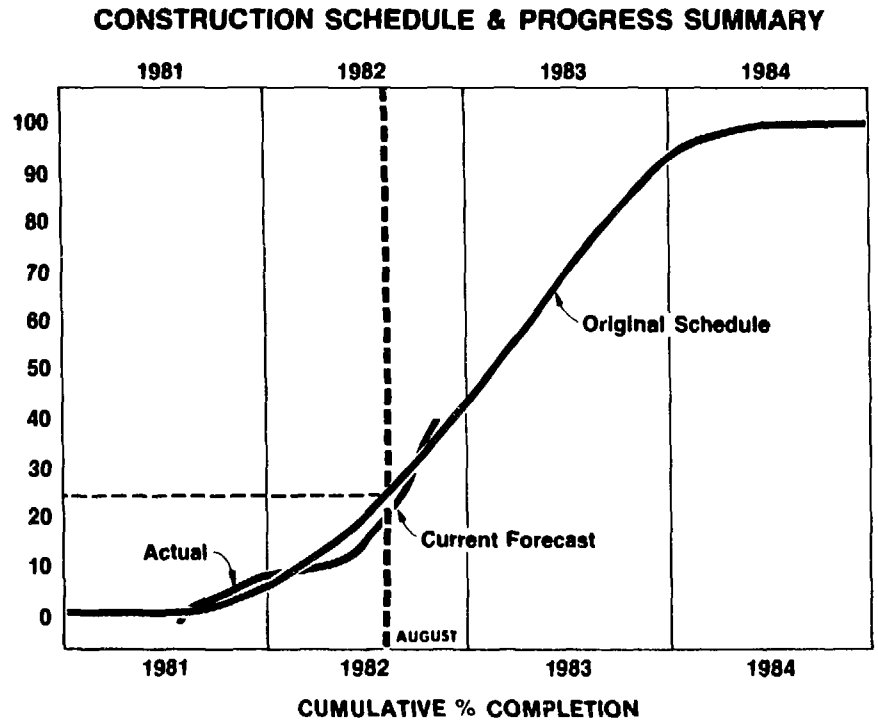
CONSTRUCTION SCHEDULE & PROGRESS SUMMARY
1981
1982
1983
1984
100
90
80
70
60
50
40
30
20
10
0
Original Schedule
Current Forecast
Actual
AUGUST
1981
1982
1983
1984
CUMULATIVE % COMPLETION

Figure 3

These early problems have been corrected and there never has been any problem with labor availability at the plant site. This is another one of the few blessings which result from a stagnant national economy. In addition, we anticipate no major future problems with construction labor due to the no strike clause we negotiated in our comprehensive project labor stabilization agreement which applies to all the building trades working at the plant site.

Table 2 shows a financial summary of the project at the end of August, 1982. As shown, over one quarter of the estimated $2.1 billion project cost was recorded on our books on August 31, 1982 and an additional 10% of the project costs are committed leaving less than 65% of total project costs to be spent over the next 27 months. We are very optimistic that we will come in at or under the total project budget.

Prospects for the Future

It was made very clear in the FERC proceedings and in the Federal Loan Guarantee for the Great Plains project that the federal supports were not intended to set a precedent for a large number of projects similar to the Great Plains project. The Great Plains project was approved prior to release of any funding from the Synthetic Fuels Corporation, but this new agency will probably reserve most funding for unique pioneer projects. Thus, most projects which follow the Great Plains project will have to break new ground in project financing.

However, one of the earlier issues in the Great Plains project was the technical viability of the project. When constructed and operating, the financial community should view large scale coal gasification projects as something technically viable. There never has been much doubt about this in the technical community, but the financial community has yet to be convinced.

The final settlement of the Great Plains regulatory issues established a gas price of $6.75/MMBTU at April 1, 1981 adjusted to reflect equally, the changes in the Producer Price Index and the price level for Number 2 fuel oil. Since various other "caps" will apply over the plant life, the price of the gas would be expected to rise, but be generally competitive with alternative fuels.

Assuming the prices of alternate fuels rise over the long term, the Great Plains project will be an economical project. Thus, it is near certain that

TABLE 2
GREAT PLAINS COAL GASIFICATION PROJECT
TOTAL INSTALLED COST SUMMARY TABLE
($1,000's)

	Recorded Cost Come to 8/31/82	Open Commitments	Estimate to Complete	Projected 12/1/84 Totals
Lummus/Kaiser Plant Cost	361,910	186,277	626,875	1,175,062
Great Plains Owners Activity Costs	142,170	40,418	592,293	774,881
Great Plains Share of Mine Development Costs	38,366	0	124,395	162,761
	542,446	226,695	1,343,563	2,112,704

Note: Above Table Excludes Accruals

future coal gasification plants will be constructed if natural fuel prices rise more rapidly than construction costs.

This still leaves the immediate prospects for coal gasification in an uncertain state due to: 1) the large capital costs involved, 2) the long lead times required to construct a project, 3) the uncertain future prices of natural fuels and 4) the uncertain future regulatory climate for sale of natural gas. The recent glut of international crude oil has dampened the prospects of many projects which were near ready for field construction.

Despite these current restraints, it still appears certain that future coal gasification facilities will be constructed. In the long term, petroleum based fuels are rapidly depleting and coal is a much larger source of energy reserves. Also coal is abundant in the U.S. and not subject to Middle East unrest. Long term, coal gasification is quite economical and the Great Plains project will prove this very shortly after it commences operations and production.

What are the prospects of expansion of the first Great Plains plant? At present, we are too occupied with the present facility to give much consideration to a plant expansion. However, the plant is designed and laid out such that the capacity could be doubled in the future and lignite coal reserves in the immediate area would support such an expansion. In addition, a second phase to the initial plant could be constructed to produce either methanol or automotive gasoline with a few changes and additions to the present unit processes. Since many of our present permits already contemplate and expansion, it is quite possible that something larger than the facility currently being constructed might be operating prior to the end of this decade.

In the more immediate future ANG is evaluating possible sale of plant by-products. As mentioned in the process discussion, the plant will recover approximately 85 tons per day of sulfur and 93 tons per day of ammonia which will be sold. We have had many studies and discussions with potential users of other plant by-products.

- **Tars, Tar Oils, Naphthas and Phenols**

  The Lurgi process produces approximately 180,000 gallons per day of tars, tar oils, napatha and phenols. Our first feasibility studies indicated that these products could be sold, but analysis of the actual by-products

showed that they were slightly different in chemical composition from petroleum based products. Discussions with potential users indicated that our quantities were too large to be blended into petroleum based tars, tar oils, naphthas and phenols but too small to be economically upgraded.

The above situation periodically changes depending upon the changing value of the products. We have had many discussions with potential marketers of these by-products and believe that some of them may be sold at some uncertain future date. In the meantime, they will be used as plant fuel which might later be replaced by other fuel when economically warranted.

- Carbon Dioxide

The plant produces 200 MMSCF/D of carbon dioxide or nearly 1-1/2 times the gas production. Carbon dioxide is currently gaining a significant market in enhanced oil recovery operations and we have held several discussions with potential purchasers of carbon dioxide which almost certainly will be marketed. Since the project is already integrated into Basin Electric's electricity production, the project has the prospect of being involved in the production of three vital energy sources: gas, electricity, and oil.

In conclusion, the Great Plains project is a huge and complex undertaking which will commercially demonstrate a number of concepts:

1. That gas interchangeable with natural gas can be economically produced from coal.
2. That a feedstock for methanol can also be economically produced. The methanol could be sold or upgraded to automotive gasoline at the plant site.
3. That other plant by-products can be produced and perhaps marketed. "Perhaps" applies to some of the plant liquid by-products and inert gases. Carbon dioxide is less speculative since there is little question it can be marketed.
4. That it is not necessary that our country be forever dependent on foreign sources of petroleum and its derivatives.

24. New Technologies For Coal: Utility Perspective

F. A. McCrackin
Director of Research and Development
Southern California Edison Company

Introduction

Southern California Edison Company is an investor-owned electric utility serving almost 9 million people within a 50,000 square mile area of the central and southern portions of California (Figure 1).

The continuing demand growth, along with the uncertainties surrounding the future price and availability of oil and natural gas, and the social and political constraints on nuclear power, have driven the utility industry to develop other energy alternatives. Some of these new, but promising, technologies are still in the early stages of development and will require many more years before they can be cost-effectively deployed. To meet the immediate increasing demands for electricity, without augmenting our nation's dependence on expensive foreign oil, Edison is actively seeking technically and economically viable, non-oil technologies which can be commercially deployed in the near future. Additional aspects considered in the selection of these technologies include environmental issues, capital requirements, and the domestic availability of the energy resources utilized.

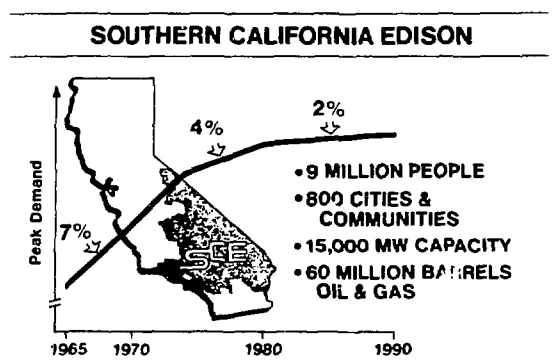

Figure 1

The Coal Resource

Coal is a domestic energy resource which can be utilized to meet some of the nation's energy needs. However, envirnomental emmission restrictions are discouraging utilities from building conventional coal-fired power plants. Therefore, the Southern California Edison Company is undertaking significant efforts to develop new, clean coal technologies for generating power. This paper focuses on technologies with near-term promise.

A large part of Edison's existing capacity base is oil- and gas-fired steam power plants (Table 1). By retrofitting existing oil- and gas-fired plants to burn coal, Edison could lower its fuel costs with reasonable capital outlay, while lessening its dependence on oil and gas.

Table 1

SCE 1981 Generation Capacity Mix

Hydro	6%		
Purchase Power	15%		
Nuclear	2%		
Coal	10%		
Oil & Gas	67%		
Total	100%	15,592	Megawatts

One retrofit approach studied by Edison involves the use of coal-based liquid fuels such as coal oil mixtures or coal water slurries. These fuels are combusted in a manner similar to conventional oil-firing with only minimal boiler front-end modification (Table 2). Furthemore, because the coal is suspended in a liquid and can be prepared away from the plant site, fuel handling and transportation is simplified. Use of existing storage tanks, pumps and piping at the plant is viable. Also, boiler tube erosion and corrosion is minimized because of the small size of the coal particles in suspension and by the use of low ash, cleaned coal.

However, this approach has constraints. The lower heat release rates and long combustion reaction times of coal fuels necessitates a substantial power derating. Furthermore, even though the use of low ash and sulfur cleaned coal reduces particulate and SO_2 emissions, these pollutants may still require stack cleanup in order to meet the environmental constraints. Also, ash handling equipment may be needed for the existing boiler.

To circumvent the potential drawbacks of the conventional combustion approach, Edison is pursuing advanced combustion technologies. The focal point of these efforts is the development of an advanced slag rejecting, two-stage combustor. Ash is removed as slag from the combustor easing low ash coal constraints. The two-stage combustion process produces extremely low NO_x emissions. Furthermore, SO_x control can be performed within the combustor minimizing the need for tail end cleanup.

This combustor would be attached to the outside of the boiler wall of an existing oil-/gas-fired plant. Combusting the coal external to the boiler reduces the necessary residence time for coal combustion within the boiler, which allows for larger coal feed rates. This, when combined with the greater gas velocities allowed by the effective removal of ash (slag) prior to the boiler tubes, minimizes the power derating associated with the fuel change.

One must note, however, that these combustors require further development. In addition, the relatively large physical size of the combustors might make certain retrofits impractical. Furthermore, the projected purchase and installation price of the combustor will add substantially to the total capital cost of the fuel change retrofit.

Nonetheless, Edison believes the possible benefits to be obtained with a coal-for-oil retrofit approach in general, and the advanced combustors in particular, merit further developmental work. Preliminary findings indicate the savings obtained by such a retrofit will more than off-set the costs. Edison is making substantial efforts toward meeting this goal.

Coal Gasification

Another promising method to utilize coal is by gasification. In this respect, Edison, Texaco Inc., the Electric Power Research Institute (EPRI), Bechtel Power Corporation, General Electric Company, the Japan Cool Water Program (JCWP) Partnership and the Empire State Electric Energy Research Corporation (ESEERCO) have joined to design, construct and operate the integration of the Texaco Coal Gasification Process (TCGP) using a nominal 1000 ton-per-day coal gasifier with a 100 MW net General Electric combined cycle electrical generation facility. The oxygen-blown gasifier produces a medium Btu synthetic gas. After cleanup of the syngas, the gas will be burned in modified combustors to power a combustion turbine.

Further energy is recovered in a heat recovery steam generator and produces additional electricity through a steam turbine (Figure 2). The integrated coal gasification - combined cycle (IGCC) approach offers great potential for coal use by utilities.

This project will serve as a major step towards the increased utilization of coal as a major source of energy and will demonstrate an alternative coal-based technology to allow the use of coal in both an economic and environmentally acceptable manner. Totally financed by the private sector, this project would be a model for the first-of-a-kind demonstration of a new coal technology on a meaningful commercial scale (Tables 3 and 4).

Artist Rendering of the Cool Water Coal Gasification Facility

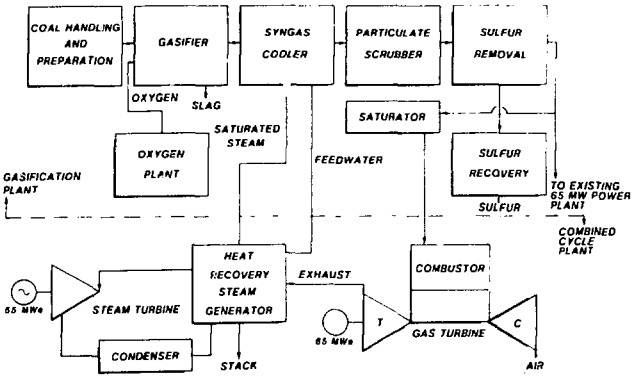

Figure 2

CWCGP Block Flow Diagram

Table 2

Conventional Combustion Technology Retrofit

Advantages	Disadvantages
• Minimal boiler modification	• Boiler derating
• Little on-site coal handling equipment	• Tail end cleanup
• Can be handled as liquid	

Table 3

Program Funding (in millions of dollars)

Participants	I Committed Equity Funds	II Program Loan Guarantees	III Additional Committee Funds
SCE	25.0	12.0	
Texaco Inc.	45.0	6.0	
EPRI	65.0	6.0	40.0
Bechtel	30.0		
General Electric Co.	30.0		
JCWP	30.0		
Sponsor			
ESEERCO	5.0		
Subtotals	230.0	24.0	40.0
Total Capital Cost			294.0
Existing SCE Facilities Credit			6.0
Total Program Capital Cost			300.0

Table 4

Program Cost Estimate Summary

	$ in Millions
Coal Receiving, Storage, Preparation	33.0
Coal Gasification	48.0
Sulfur Removal/Recovery	15.0
Steam, Condensate and Water	9.0
Power Generation Equipment	45.0
Supporting Systems and Equipment	24.0
Start-up, Operator Training, Initial Operations	22.0
Subtotal	196.0
E-C Engineering & Management	34.0
Other Program Expenses	33.0
Contingency	31.0
Subtotal	98.0
Total	294.00

Specifically, the Cool Water Coal Gasification Program (CWCGP) objectives are as follows:

- Construction of an integrated coal gasification combined cycle electric generating facility of commercial size equipment.
- Demonstration of the following:
  - compliance with environmental regulations
  - operational flexibility and reliability
  - coal feed stock flexibility
  - overall integrated systems controls under various operating conditions including start-up, turndown and load following
  - alternate plant or process components including combustion tests of the medium Btu gas in a conventional boiler
- Development of the following:
  - precise economic data
  - scale-up criteria
  - operating, maintenance, safety and training procedures
  - precise environmental emissions data under different operating conditions and with different types of coal.

The nation's first power plant, based on modern U.S. coal gasification technology, is well on its way

to becoming a reality at Southern California Edison Company's site in the Mojave Desert. Construction of the plant was started in December 1981 and is scheduled to be operational during the third quarter of 1984, to be followed by a seven-year demonstration and testing period. The IGCC concept with its modular application will enable utilities to install new electric power generation capacity in increments--manageable both financially and in terms of generation need. The strong commitment of a number of large energy companies makes the success of this major technological demonstration at Cool Water an attainable object. In addition, this program was selected by the U.S. Synthetic Fuels Corporation in September 1982 to enter final negotiations for a price support agreement during the operational phase.

Active members of the energy field can obtain direct and timely benefits by joining in the Cool Water Program. Some of these benefits are listed in Tables 5 & 6. In this respect the project organizers invite other energy groups to become participants or sponsors in this important program.

Table 5

CWCGP PARTICIPANTS

- Commits $25 Million
- Opportunity to recover contributed funds
- Membership on board of control and management committee
- Share program license royalties
- 25% royalty credit
- Program information
- Have engineers and technicians trained
- Coal tested in the plant
- Testing of process, material and equipment
- Publicize participation
- Own undivided interest

TABLE 6

CWCGP SPONSOR

- Commits $5 million
- Opportunity to recover 50% of contributed funds
- 5% royalty credit
- Program information, plant visits, publicize sponsorship
- Coal tested in the plant for a fee
- Own undivided interest

25. The Industrial Energy Outlook - The Role of Coal

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Chemical Group
The B F Goodrich Company
Cleveland, Ohio

In 1980, U.S. consumption of purchased fuel and electric energy for heat and power by manufacturing establishments was almost 12 quads.[1,2,3,4] This is the equivalent of almost one-half billion tons of coal and represented approximately 16% of total U.S. energy consumption in 1980.[5] However, less than 12% of the total energy purchased by manufacturing for heat and power in 1980 was coal.[6] (Table 1)

Table 1
U.S. ENERGY CONSUMPTION
1980

	Quads*	Coal Equivalent Million Tons
Total	75.9	2,900
Fuel and Electricity Purchased for Heat for Power by Manufacturing	11.9	450
- Coal	1.3	50

*A quad is 10^{15} Btu

SOURCE: See Notes 1, 2, 3 and 4

Current and Potential Industrial Uses of Coal

There have been many forecasts of the potential for the increased use of coal in manufacturing--most filled with rosy promises of rapidly growing demand--that, in fact, have failed to come to pass. As an example, in February, 1982, the U.S. DOE dropped its projection of industrial use of coal in 1990 by 25% as compared to its 1981 forecast.[7] (Table 2)

Earlier this year, the National Coal Association prepared a report on the outlook for coal use. Its "most likely" forecast for total industrial coal consumption in 1990 is 147 million tons which is twice the Association's estimate of 1980 use.[8] (Table 3)

Table 2

COMPARISON OF DOE PROJECTIONS FOR
1990 INDUSTRIAL USE OF COAL

	Mid-Range Projections (in Quads)	
Forecast Date	1981	1982
Non-Metallurgical Uses	4.7	3.4

SOURCE: See Note 7

Table 3

NATIONAL COAL ASSOCIATION
1982 FORECAST
Industrial Coal Consumption
(Millions of Tons)

	Actual	Forecast		
	1980	1985	1990	1995
Low	-	89	113	140
Most Likely	74	104	147	184
High	-	126	180	234

SOURCE: See Note 8

In July, 1982, the Department of Commerce estimated that industrial consumption of coal for process heat and steam in the year 2000 would be 173 million tons which projects a growth of 240% from the Commerce's estimate of 1981 use.[9] (Table 4)

Table 4

COMMERCE DEPARTMENT 1982 FORECAST -
INDUSTRIAL COAL CONSUMPTION FOR
PROCESS HEAT AND STEAM

Year	1981	2000
Million Tons	51	173

SOURCE: See Note 9

A note of caution is offered for those looking for good news. There are few signs that the industrial consumption of coal will grow rapidly in the near future. The combination of economic, regulatory and institutional barriers, combined with tremendous uncertainties, will continue to delay what ought to be inevitable. This paper will discuss some of the factors contributing to the slow growth and review the new technologies that offer encouragement.

Where and How Does Industry Use Energy?

Industrial energy consumption is concentrated in a limited number of sectors, and 76% of 1980 purchased energy use was in six industrial groups.[10]

Table 5

INDUSTRIAL ENERGY CONSUMPTION BY SECTOR

SIC Code	Major Group	Total Energy (Quads)	Coal for Heat and Power (Million Tons)
33	Primary Metals	2.3	4.5
28	Chemicals	2.2	13.0
26	Paper Products	1.3	8.9
29	Petroleum	1.2	0.3
32	Stone, Clay & Glass	1.1	12.3
20	Food Products	0.9	4.5
-	All Others	2.9	6.5
	Total	11.9	50.0

SOURCE: See Note 10

Today, essentially all coal used by industry--other than metallurgical use--is as boiler fuel. It appears that boiler fuel use of coal is the only use with the potential to grow significantly by the end of the century.

In the next 15 to 20 years, there is little potential for any significant growth in the use of coal for chemical feedstocks. There have been a number of technical papers on this subject, but the only production facility which has been announced is a plant in Kingsport, Tennessee of Eastman Kodak to

produce acetic anhydride using coal to make synthesis gas as a starting raw material.[11] This plant represents a significant forward step in the use of coal, but it should be noted that it is being built as a result of fairly unusual circumstances. As a whole, available supplies of natural gas and clean petroleum products as feedstocks are likely to be available for the next 10 to 20 years at prices that will not justify the high capital investment required to change the complex chemcial structure of coal into the chemical building blocks required by most of the chemical industry.

Over 60% of the natural gas consumed by industry is used as a process fuel in direct- or indirect-fired applications requiring particular flame characteristics or precise temperature control, or in gas turbines or engines.[12] Coal could be gasified to meet such applications. However, with projected supplies and prices of natural gas, it appears unlikely that much coal will be used for such applications in the next 10 to 20 years.

When these other industrial uses are eliminated as near-term potential markets for coal, only oil and gas use are left as fuel in medium- and large- sized industrial boilers--an estimated equivalent of over 100 million tons per year of coal--as the chief target for growth in industrial use of coal.[13] (Table 6) Even here, there are major obstacles.

Table 6

OIL AND GAS USED AS FUEL
IN MEDIUM AND LARGE INDUSTRIAL BOILERS
IN 1979*

Quads	Equivalent Tons of Coal Per Year
2.85	109 Million

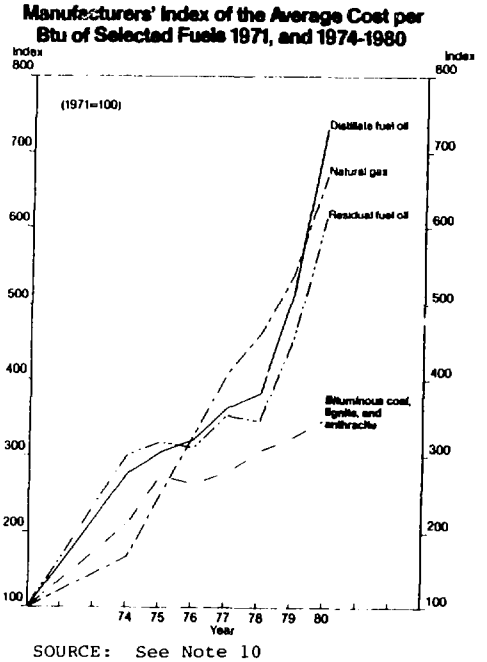
*50,000 lb/hr steam capacity and larger

SOURCE: See Note 13

Incentives and Obstacles to the Use of Coal

There are two perceived incentives for the increased industrial use of coal:

- Lower fuel cost as compared to oil and gas. This figure shows the increasing spread between 1970 and 1980 in costs of coal as compared to other industrial boiler fuels. The spread has widened since 1980 and is expected to continue to grow. (Figure 1)



SOURCE: See Note 10

Figure 1

- Increased supply security in the event of curtailments of oil and gas. Most past programs for allocation in the event of shortages of supplies of natural gas and distillate fuel oils have assigned the lowest priorities for the use of these clean fuels in large industrial boilers.[14]

There are three general categories of obstacles and uncertainties which have delayed the increased use of coal as industrial boiler fuel:

- Economic
- Institutional
- Regulatory

These have combined to result in relatively slow rates of past and projected growth.

Balanced against the potential for lower fuel costs are the high capital and operating costs for coal-fired boilers. In late 1979, Davy McKee prepared a study for the U.S. DOE in which it compared industrial boilers in various sizes using alternate fuels.[15] This study showed that for a 100,000-pound-per-hour boiler, which is a fairly typical size of industrial boiler, the investment for an oil or gas boiler was only 13% to 15% as large as for a spreader stoker coal-fired boiler with flue gas clean-up. (Table 7) Even when incorporating the advantages of the lower cost fuel, the steam produced from the coal-fired boiler was still 50% to 80% higher in cost than steam from oil or gas. If anything, that disadvantage is greater today than in 1979 because of inflation and the higher cost of money.

Table 7

COST COMPARISON - INDUSTRIAL BOILERS
BOILER SIZE - 100,000 POUNDS PER HOUR

	Boiler Type		
	Coal	Oil	Gas
Capital Cost* (Million Dollars)	8.6	1.3	1.1
Total Steam Cost* (Dollars per Thousand Pounds)	7.4	5.0	4.0

*1979 Dollars

SOURCE: See Note 15

Adding to the impact of the high investment cost are the high cost and shortage of a capital that industry faces today. Many companies have more desirable potential projects than money available for funding. In some cases, new production facilities may be required for the company to maintain existing market share or to seize new markets or to comply with regulatory requirements. In most cases, such projects will take preference over equally profitable projects to reduce energy costs.

Most projects to convert from the use of oil and gas to coal are justified by the projected increasing spread between the price of coal and the alternate boiler fuels. Justification of the project involves discounting this future saving in fuel cost back to the present and balancing it against the required investment. However, this year there have been a number of questions about the likely rate of increase in prices of oil and gas. One gas company is proposing two-tier prices for natural gas which could make it available as boiler fuel at costs even less than the system average costs of purchased gas.[16] Further, there have been proposals to amend the Natural Gas Policy Act of 1978, which established a schedule for the price deregulation of many classes of natural gas. Some proposals include delays in the present schedules for price deregulation of some classes of natural gas and/or repeal of the incremental pricing of interstate gas used as industrial boiler fuel.

In trying to assess how rapidly industry will convert its boiler fuel use from oil and gas to coal, it should be recognized that most of the conversion potential is in existing plants where existing oil and gas boilers have many remaining years of useful life. In order to justify the conversion, the fuel price differential must be large enough to justify shutting down these existing boilers.

As a result of the uncertainty of future fuel oil and natural gas prices and the very high cost and scarcity of capital for industrial projects, many industrial coal boiler projects have been delayed.

Institutional barriers have also delayed the increased industrial use of coal. These barriers exist in coal producing and marketing organizations, the transportation and distribution sector and in the potential coal consuming industries.

Industrial operators think of coal as a dirty fuel. Storage and handling of coal require a large amount of space. Coal boilers are complicated to operate and require much more maintenance compared to oil and gas boilers. The new technologies being considered for the industrial use of coal all involve some level of technical and economic risk. All of these serve as justifications for industry's reluctance to go to coal.

At the same time, coal production, marketing, and transportation is not geared to supply the industrial market. The experience of many coal producers is chiefly in negotiating long-term contracts with utilities, and their sales forces are not experienced in selling to industry that usually seeks competitive bidding on shorter term contracts.

Annual coal consumption in an individual new industrial boiler will probably range from 50,000 to 200,000 tons. Such a level of use makes it difficult to secure low rates for shipping and unloading coal. This barrier might be overcome by establishment of regional terminals for bulk handling, storage and distribution of standardized grades of coal from several suppliers to industry. However, few such facilities are available, and their absence adds significantly to the potential delivered cost of coal for new industrial boilers.

Major obstacles and uncertainties are in the regulatory area. A great question is what level of emissions will be permitted from future industrial boilers. The U.S. EPA is currently developing emission standards for industrial boilers. Some industrial groups are urging that these future standards be relaxed because of the poor cost effectiveness of reducing emissions from relatively small industrial boilers as compared to large utility boilers.[17] At the same time, there are opposing pressures to make the standards even more rigorous than at present. For example, one proposal is to require not only an absolute limit on the amount of SO_2 emissions but also a percentage reduction based on the sulfur content of the fuel. This uncertainty on emission standards has resulted in major questions as to what process designs and types of coal will be required for industrial boilers to meet future emission standards.

Obtaining the necessary environmental permits for coal-fired boilers can be a long and complicated process. One or more permits are required before construction can begin. In some cases, lengthy periods of ambient air monitoring to develop background information on air quality are required before a permit can be issued. Technology reviews, requiring either Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) Technology, are also required prior to permit issuance. These reviews are subjective and result in uncertainty as to the acceptability of environmental controls.

Another kind of regulatory barrier to new technologies for using coal for generating steam is an IRS regulation which deals with the granting of the right to use low-interest rate revenue bonds for financing of pollution-control facilities. Add-on pollution control devices such as flue gas desulfurization are eligible for this incentive, but the present interpretation by the IRS is that other types of equipment incorporated in the process to prevent pollution such as fluidized bed combustion do not qualify.

Another regulatory uncertainty is the role that cogeneration will play in optimizing the economics of new coal-fired industrial boilers. In 1978, Congress passed the Public Utility Regulatory Policies Act or PURPA which provided incentives for industrial co-generators. Implementing federal regulation has been challenged in the federal courts and many states have still not issued implementing regulations.

Still another area of regulatory uncertainty is the possiblity of repeal of the Power Plant and Industrial Fuel Use Act of 1978 which is the basis of the existing U.S. DOE regulations that prohibit the use of oil or gas as a primary fuel in any new industrial boiler with a capacity over 100,000 pounds per hour. Repeal of the Fuel Use Act would remove the authority of the federal government to require the use of coal in new industrial boilers. Obviously, this delays any decision by an industrial operator who cannot justify a coal boiler on the basis of projected economics.

The coal producing and consuming industries need to work with state and federal authorities to identify and reduce these various regulatory obstacles and uncertainties which make it so difficult to move ahead on new industrial coal boiler projects.

Added to these various economic, institutional and regulatory barriers and uncertainties on the use of coal as industrial boiler fuel is the question of what kind of boiler to use.

Existing and New Technologies

Technologies under consideration for industrial use of coal can be broken into three general categories:

- Existing coal boiler designs with or without add-on emission control devices
- Developing technologies to utilize existing oil and gas boiler designs
- New boiler designs

Existing industrial coal-fired boiler designs can be conveniently classified based on the method of coal addition. Stoker boilers use various types of mechanical and gravity arrangements to feed the coal to a grate system. With pulverized coal boilers, the coal is pulverized and injected into the firebox. Generally, pulverized coal boilers are used for the larger installations; whereas, the stoker designs are more economical for a capacity of less than 250,000 pounds per hour. There are many small boilers in industrial plants, but it appears that the target for the use of

coal is boilers larger than 50,000 pounds per hour. In fact regulations under the Fuel Use Act exempt boilers under 100,000 pounds per hour from the requirements to use coal. Industrial boilers are usually small compared to utility boilers, and a study found that 97% of industrial boilers are of a size less than 250,000 pounds per hour, and when all industrial steam capacity was considered, 82% of this capacity comes from boilers of a size less than 500,000 pounds per hour.[18]

There are two approaches for the use of coal in the existing designs of industrial coal boilers. The first is to utilize a "compliance" coal without flue gas desulfurization equipment. There is no clear-cut specification for compliance coal, but generally it is considered to be a coal that can be burned without exceeding permitted emissions for SO_2. Some kind of particulate control is usually required.

For a new boiler, it is uncertain whether compliance coal may be used since the new source review procedures for enviromental construction permits require a case-by-case determination of acceptable control technology. The decision to install a new coal boiler of conventional design without add-on flue gas desulfurization equipment has to include consideration of future emission standards, projected prices of low-sulfur coal and the acceptability to the state and federal reviewing agencies. Some companies believe that the standards now permit or will be modified to permit such installations. This is not the view of B F Goodrich, and as a result, any new coal-fired boiler which Goodrich installs must include provisions to control SO_2 in the emissions.

The second approach with conventional coal-fired boiler designs is to use add-on flue gas desulfurization equipment, generally subdivided into two categories -- wet and dry scrubbers. This is an emerging technology which is not yet proven in industrial service. This does not mean that they cannot be operated to remove SO_2, but rather that the operating or maintenance costs are significantly higher than considered acceptable or that the service reliability is less than required. In addition, many of these processes generate a wet sludge that involves disposal problems.

The Chemical Group of Goodrich is satisfactorily operating a 250,000-pound-per-hour spreader stoker boiler with a wet scrubber using high-sulfur Illinois coal. This new boiler which is in the Goodrich plant at Convent, Louisiana was started up in 1981. The scrubber is a single stage alkali design that is

economic because of the availability of low value by-product alkali streams at the plant location.

Thus far, the impression is that the various dry scrubbing flue gas desulfurization processes that are coming along after the wet process are offering considerable promise, particularly for retrofitting existing coal boilers.

Another approach is to use coal in a boiler design originally intended for oil and gas. Industry has a number of package boilers in the size range of 50,000 to 150,000 pounds an hour designed to burn gas or low-sulfur fuel oil. The effort has been to reduce the fuel cost for such boilers by replacing the oil or gas completely or partially with coal.[19]

One method is to use coal-oil mixtures. Coal is ground and mixed with heavy fuel oil using a suspending agent at a central plant and shipped to the point of use. The particular coal and oil used are selected to produce an acceptable level of SO_2 in the emissions. Most of the ash in the coal goes overhead with the flue gas and is removed in a particulate control device. Coal-oil mixtures have been used for such a short time that there is only limited experience of the impact on boiler life or maintenance due to the particulates in the combustion gases. Coal-oil mixtures are prepared in a range of 40% to 60% coal, so this design offers an obvious advantage in the event of a fuel oil shortage. However, since (1) oil remains a signficant part of the fuel, (2) some expense is required for the preparation and shipping of the mixture and (3) oils and coals must be selected to meet SO_2 emission requirements, it appears that this process has only limited potential for reducing fuel cost as compared to burning fuel oil. Further, the fuel cost could be expected to swing widely with changes in oil prices. My impression is that potential fuel savings are only 10% to 20% as compared to the use of oil, and this estimate does not include possible additional operating or maintenance costs.

Another approach to the use of coal in oil/gas boilers is use of coal-water mixtures. Here, the coal is ground and mixed with water using a suspending agent at a central point and distributed to the point of use. It is my understanding that stable mixtures containing up to 70% coal have been prepared. The coal is selected to meet SO_2 emission requirements. Again, most ash in the coal is carried overhead as particulates in the flue gas, and add-on particulate control equipment is required. There has been limited industrial experience with this process, but it is my understanding that a test burn in an industrial boiler

is planned for the near future. Concerns include system ability to handle the particulates without excessive wear or corrosion and how much derating will result.

A derivative of this design is use of a coal-steam mixture. The coal is pulverized at the point of use, using steam as the energy source. The pulverized coal-steam mixture is injected in the boiler firebox. Reports indicate that good combustion has been achieved. Obviously, the amount of steam required is critical to the economics of this process. Again, the coal must be selected to meet SO_2 emission requirements, and some type of particulate control will be required.

Another process which has been considered for adaption to existing oil/gas boiler designs is a slagging cyclone coal gasifier-combustor. This is a staged combustor in which coal is heated in a fuel-rich mixture using an arrangement that makes it possible to continually draw off molten slag. The volatiles from the coal and combustion gases are introduced into the firebox where combustion is completed. This approach reduces the amount of solids that must be handled in the boiler and the staged combustion promises to produce low levels of NO_x. While early work on this process was sponsored by DOE, it is apparently now being pursued by private industry.

The most promising approach for the use of coal to generate steam in industrial plants in an environmentally acceptable fashion is fluidized bed combustion. Not only does this process recover the sulfur from the coal as a dry residue, but because of the low combustion temperatures, it produces a low level of nitrogen oxides--NO_x. Currently, the capital cost appears to be competitive with conventional industrial coal boilers with add-on flue gas desulfurization. It is believed that strong potential exists for eventual capital savings as compared to the add-on approach. Further, significantly lower operating and maintenance costs are anticipated.

Fluidized Bed Combustion

In the '70's, as world prices of energy from oil and gas increased and as the U.S. and other petroleum importing countries recognized their increasing dependence on a limited number of foreign sources for crude oil, research was accelerated to find improved methods of using the relatively abundant supplies of high-sulfur coal. Fluidized bed reaction technology

had been pioneered in the American refining and petrochemical industries and by 1970 large fluidized bed reactors were in many refineries and chemical plants around the world. One approach to solving the problem of using coal was to attempt to develop an FBC coal boiler. This effort began in laboratories around the world and moved to the pilot plant and demonstrations phase.

For those who may not be familiar with the process, fluidized bed combustion--or FBC--involves feeding a mixture of coal and limestone to a combustion chamber where this mixture is supported on a grid and suspended or fluidized by blowing the combustion air through the bed. The mixture is ignited using gas or oil and then the combustion temperature is controlled at 1,500-1,600°F. Water in tubes in the bed and/or in the space above the bed is heated to generate steam. The SO_2 formed from the sulfur in the coal reacts with the lime formed from the limestone to form gypsum. A dry residue composed of ash from the coal, gypsum and unreacted limestone is drawn off, both as bottom ash and as fly ash.

Today, there are two general types of fluidized bed combustion -- fixed beds and circulating beds.

Fixed Bed FBC Boiler Systems

The fixed or "bubbling"bed FBC boiler is the first generation of FBC technology. A bed of burning coal and limestone is maintained in a fluid-like state by the flow of combustion air through it. A support grid at the bottom of the bed helps distribute the combustion air so that the bed material behaves like a boiling or "bubbling" liquid, seeking its own level and allowing movement of material from one part of the bed to another.

Coal and limestone are introduced into the combustion chamber by a mechanical or pneumatic feeder that distributes them either above or into the bed material. Primary air is introduced at the bottom of the bed in a controlled ratio with the coal and limestone to secure efficient combustion and capture of sulfur and at the proper velocity to keep the bed fluidized.

The ash from the coal, the gypsum from the reaction of the SO_2 and limestone, any unburned coal, and unreacted limestone are removed through downcomers in the bed and as fly ash from particulate control equipment.

The heat produced by the burning of the coal is removed by boiler tubes, some of which may be part

ially or totally submerged in the bed material. This serves a dual function of extracting the heat of combustion from the bed to produce steam and controlling the bed temperature at 1500 to 1600°F, which is the optimum for the SO_2 removal reaction. Other tubes are above the bed in the combustion chamber and in an attached convection section.

Operation of this first generation of FBC boiler technology requires that the size of the bed materials, as well as the velocity of the combustion air, be controlled within narrow limits to make certain that coal and limestone are not carried out of the bed.

One 100,000-pound-per-hour demonstration unit funded by the U.S. DOE has been operating at Georgetown University since 1979. A 50,000-pound-per-hour unit jointly funded by the State of Illinois and the U.S. Government at the Great Lakes Naval Training Center began operating late last year. A 200,000-pound-per-hour unit is currently in start-up at the TVA plant at Paducah, Kentucky.

The first-generation FBC boiler demonstration units are also being used to investigate techniques to improve coal and limestone utilization and overall efficiences. The fixed bed FBC boiler requires that the majority of ash and gypsum be removed from the bed itself. However, unreacted limestone and unburned coal are also removed from the bed during this operation. These materials still have a very high heat content since the bed is operating at 1500-1600°F. This results in the need for additional equipment to minimize the heat loss and improve efficiency.

One of the basic requirements of an industrial boiler is that it be able to rapidly increase or decrease steam production as demand changes. This is difficult to accomplish in the fixed bed FBC boiler due to the requirement to operate at a limited range of velocities. If steam demand suddenly decreases, the supply of fuel will be reduced, but a proportionate decrease in combustion air could reduce velocity below the minimum required to keep the bed fluidized. If this happens, mixing within the bed decreases dramatically, causing incomplete combustion, smoking and poor SO_2 capture. If the combustion air is not reduced, efficiency decreases and the bed temperature may drop below the termperature required for optimum SO_2 capture.

If the steam demand suddenly increases, the coal and limestone can be increased, but the combustion air must be closely controlled to avoid carrying the bed material out of the combustion chamber. Maintaining the proper ratios of air, coal and limestone as well

as the uniform temperature required for the reaction to remove SO_2 during these load changes are limitations of fixed bed FBC boilers that are still being studied.

Circulating FBC Boiler System

With the recognition of the limitation of the fixed bed FBC boilers, the search began for alternate technologies. This has resulted in designs by several organizations of a second generation of FBC boilers in which the bed of coal and limestone does not establish a specific level in the combustion chamber but varies in density and circulates through the entire combustion zone of the boiler. These are usually referred to as circulating or second-generation FBC boilers.

The principle of the circulating fluidized bed system can be explained by examining the relationship between differential pressure and superficial gas velocity for a bed of particles. Figure 2 shows this relationship.

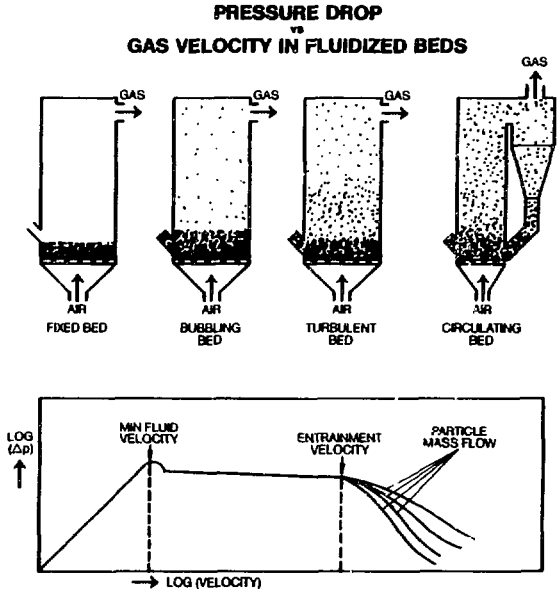


Figure 2

For a fixed bed, the log of differential pressure is approximately proportional to the log of gas velocity. As the gas velocity increases beyond the minimum fluidization velocity, the particles begin to expand and become fluidized, and a distinct bed level is visible in the fluid bed. The differential pressure remains almost constant until the bed material begins to elutriate or be carried out of the bed at the entrainment velocity of a fixed bed. The degree of turbulent mixing continues to increase between the minimum and the entrainment velocity.

Beyond the entrainment velocity, some particles are carried out of the bed, and a continuous process is maintained by recirculating the particles to the bottom of the bed. The entrainment velocity marks the transition from a fixed bed to a circulating bed. Beyond this velocity, the differential pressure becomes a function of velocity and solids recirculating rate. This principle has been applied to FBC coal-fired boilers.

A fixed fluidized bed operates with air velocities that only vary between the minimum and the entrainment velocities. At higher velocities, the bed material becomes entrained, and there is carry-over of unburned particles from the combustion chamber. At the velocities close to the minimum fluidization velocity, the bed or portions of the bed may slump, causing localized hot spots.

In contrast to the fixed bed, the circulating fluidized bed system can use greater air velocities because the entrained particles are seperated from the hot gases and reinjected into the bottom of the combustion chamber. Turndown ratios of up to 3:1 can be achieved by changing the air flow rates and fuel feed. Load changes greater than 20% within 10 minutes have been demonstrated.

Goodrich Coal Strategy

The B F Goodrich Company has approximately 70 industrial size boilers in its U.S. manufacturing facilities. About half of these are in our chemical plants. Several years ago, the Company, concerned about the rising prices of oil and gas and the danger of boiler fuel interruption in the event of shortages, established as part of its energy policy the goal that by 1990, gas- and oil-fired base load steam generation in our chemical plants would be converted to coal or other alternate energy sources. Considerable progress has been made toward this objective. As a measure of progress, in the last

three years, in the Chemical Group, two new coal-fired boilers have been started up and two older boilers rehabilitated so that this year 28% of total steam will be generated from coal as compared to only 13% in 1980. Further, steam generated from natural gas and fuel oil has dropped from 46% to 29% over the same period. Most of the remaining steam is generated from process heat recovery and waste products, with a small amount purchased. (Table 8)

Table 8

GOODRICH COAL STRATEGY STATUS

	1980	1982
Coal Boilers in Operation	2	6
Steam Source	**1980**	**1982**
Coal, Percent	13	28
Waste Heat or Waste Fuel, Percent	30	33
Purchased Steam, Percent	11	10
Oil/Gas, Percent	46	29

As part of the overall move to switch from oil and gas, Goodrich began studying available technologies for generating steam from coal in the late 1970's. Most of them were found to be lacking, particularly in light of present and projected emission requirements. In many cases, boiler designs were little changed from 25 years earlier. Some of the technologies that were in the research or development stages were reviewed.

One of the emerging technologies that our company found to be particularly interesting was the fluidized bed combustion process. Goodrich was probably particularly open-minded to this process because of its broad experience in operating fluidized bed chemical reactors in several U.S. and foreign chemical plants. However, it was concluded that the performance characteristics of the first generation of fluidized bed combustion boilers, which had fixed or bubbling beds, were inadequate to meet Goodrich's industrial requirements of quick response time and high turndown ratio.

The Goodrich Henry, Illinois Project

In searching for a solution to this problem, Goodrich looked at advanced developments. In Finland, the Ahlstrom Company, using a design called PYROFLOW, had been operating a circulating fluidized bed combustion boiler pilot plant since 1976 and a 45,000-pound-per-hour boiler in production service since 1979.

Figure 3 is a conceptual drawing of the PYROFLOW circulating FBC boiler system.

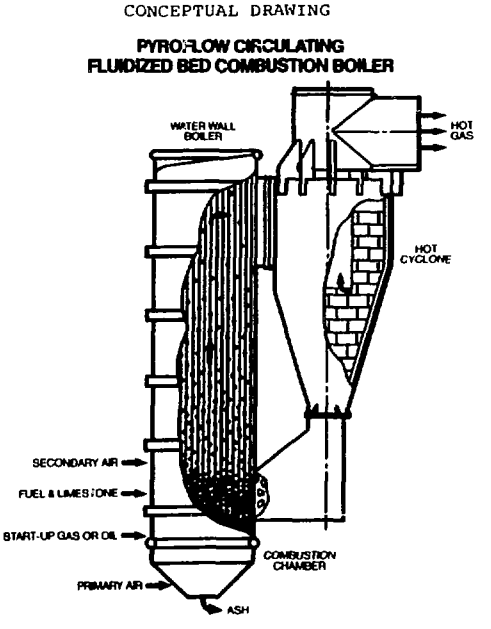


Figure 3

It was developed by the Ahlstrom Company of Helsinki, Finland and offered in the U.S. by the Pyropower Corporation of San Diego.[20,21] Fuel and limestone are fed into the lower part of the combustion chamber, and primary air is introduced through a supporting grid. Because of the turbulence in the circulating bed, the fuel mixes quickly and uniformly with the bed material. There is no fixed bed depth. The density of the bed varies, with the highest density at the level where the fuel is introduced. Secondary air is introduced at various levels to (1) ensure that the gas velocities in the upper part of the combustor are

high enough for particle entrainment, (2) to provide staged combustion conditions to reduce production of NO_x, and (3) to supply air to burn fines in the upper part of the combustion chamber.

A combustion temperature of 1550°F is optimum for sulfur capture. This temperature is reasonably constant throughout the process because of high turbulence and circulation of solids. This low combustion temperature, along with staged secondary air injection, results in minimal NO_x formation.

Velocity of the hot gases is reduced as they leave the combustion chamber. This reduction, along with an increase in cross section, causes large entrained particles of coal and limestone to drop out of the gas stream into a hot cyclone collector. This solid material is a non-mechanical seal to achieve high raw material efficiency. Solids too small to drop out in the hot cyclone collector are carried to the mechanical separator and baghouse for final particulate removal from the cooled gas stream before it is discharged to the atmosphere. Residue is removed from the bottom of the combustion chamber as bottom ash and from the baghouse as fly ash.

A portion of the heat is absorbed in the combustion chamber, and the remaining heat is recovered in the convection section of the boiler. There are no tubes in the dense portion of the bed.

The combustion chamber is of water wall construction that provides a gas-tight enclosure. The lower portion, which is the dense bed region, is partially covered with refractory.

The cyclone collector, which is located at the outlet of the combustion chamber, is a steel vessel lined with two layers of castable refractory. The outer layer is designed for the high-temperature and abrasive characteristics of the entrained solids; the inner layer is a lightweight insulating refractory.

In 1981, Ahlstrom started up a 200,000-pound-per-hour circulating fluidized bed boiler in the base load steam supply for its paper mill in Kauttua, Finland.[22] After a series of visits by Goodrich engineering personnel and executives, including witnessing of performance tests in Finland, we concluded that this technology offered sufficient advantages to justify the technical risk of the installation of the first circulating FBC boiler in a U.S. industrial plant, has been previously announced. The site selected for the plant was in Henry in Marshall County, Illinois on the Illinois River, about 120 miles southwest of Chicago. As with any first-of-a-kind unit, this installation involved significant technical and economic risk.

In order to mitigate this risk, Goodrich submitted a proposal to the Illinois Department of Energy and Natural Resources (DENR) in response to its 1981 Coal Bond Fund Program Opportunity Notice for the Development and Demonstration of Technologies Enhancing the Use of Illinois Coal in the Industrial/Commercial Sector. After evaluation of the project and plans by both the Illinois DENR and the Illinois Energy Resources Commission, the State of Illinois offered a $4.3 million grant under its Coal Bond Fund Program to assist in the funding of our project. Goodrich is currently involved in obtaining environmental permits, preparing layout studies and other preliminary engineering and evaluating various Illinois coals and limestones for use in the project.

The project has been slowed by the present poor economic climate, but Goodrich intends to ask its Board of Directors for the remaining funds required for construction of this project when the economic climate brightens and earnings improve. It is projected that the PYROFLOW FBC boiler planned for Henry will burn 50,000 tons per year of high-sulfur Illinois coal and use 14,000 tons per year of Illinois limestone to capture the SO_2.

Boiler capacity will be 125,000 pounds per hour of saturated steam at 400 psig. The boiler is being designed to use 3.5% sulfur Illinois No. 6 coal, but will have the capability to utilize coal with a sulfur content of up to 5%. Design limestone use is based on 2.5 molar calcium-sulfur ratio, although we hope to reduce this to less than 2.0 during process optimization after the boiler is in operation.

The steam will be used to supply the existing process steam requirements of the plant. Currently, steam is provided by two 100,000-pound-per-hour gas/oil boilers which will be used to provide backup capacity for the new FBC boiler. A construction schedule of 18 to 24 months is projected, and the preliminary estimate of total project cost is $21.3 million.

In recognition of the grant from Illinois, Goodrich has agreed to make operating information on the unit available to the State for dissemination to other industrial boiler operators and to permit visits to the facility by others in the industrial sector who may be interested in using this innovative technology.

Summary

In summary, the major potential for increased industrial use of coal is in the replacement of oil

and gas used for steam generation. This market is estimated at the equivalent of approximately 100 million tons per year of coal.

However, relatively slow growth of coal into this market is anticipated because of a number of economic, institutional and regulatory barriers and major uncertainties. These obstacles will have to be reduced or eliminated and uncertainties lessened if coal is to capture a significant share of the industrial boiler fuel market by the end of this century.

A number of new technologies are being studied for the use of coal to generate steam in industrial plants. Goodrich believes the most promising of these is circulating fluidized bed combustion which not only promises to deal with the problem of SO_2 emissions, but produces a low level of NO_x and a dry residue.

Goodrich, working with the State of Illinois, has plans to install a second-generation fluidized bed combustion boiler at its Henry, Illinois plant. The sucessful operation of this unit will stimulate the use of high-sulfur coal in the industrial sector for steam generation. In furtherance of that goal, when the plant is operating, Goodrich invites any interested individuals to tour the plant and evaluate the process on a first hand basis.

NOTES

1 U.S. Department of Commerce, Bureau of the Census, "Fuels and Electric Energy Consumed, Industry Groups and Industries," 1980 Annual Survey of Manufacturers, August, 1982.

2 A "quad" is a quadrillion Btu or 10^{15} Btu.

3 For consistency, most government energy figures in this paper are for the year 1980, because some 1981 data are not year available.

4 This value does not include fossil fuels used as raw materials such as in the metallurgical and petrochemical industries and for asphalt, lubricants and solvents.

5 Total U.S. energy use in 1980 was 75.9 quads according to the U.S. Department of Energy, Energy Information Administration, Monthly Energy Review, August, 1982.

6 Coal at 26.2 million Btu per short ton.

7 U.S. Department of Energy, Energy Information Administration, 1981 Annual Report to Congress, Vol. 3, Energy Projections, Table 3.3, "U.S. Supply/Demand Balances: Comparison of 1990 Projections," February, 1982, p. 157.

8 National Coal Association, Looking Ahead to 1995 - A Forecast for U.S. Coal, Table IV-1, "Industrial/Retail Coal Consumption," 1982.

9 Joseph F. Gustaferro, U.S. Department of Commerce, Office of Economic Affairs, U.S. Energy for the Rest of the Century - 1982, July 2, 1982.

10 U.S. Department of Commerce, Bureau of the Census, "Fuels and Electric Energy Consumed, Industry Groups and Industries," 1980 Annual Survey of Manufactures, August, 1982.

11 H. W. Coover, Jr. and R. C. Hart, "A Turn in the Road: Chemicals from Coal," Chemical Engineering Progress, April, 1982 pp. 72-75.

12 This figure is my estimate developed from published estimates of natural gas used as industrial boiler fuel:

U.S. Department of Energy, Energy Information Administration, "Survey of Large Combustors: Report on Alternative-Fuel Burning Capabilities of Large Boilers in 1979," Industrial Energy Consumption, February 12, 1982.

and natural gas used as petrochemical feedstock:

George B. Hegeman, Arthur D. Little, Inc., "1980 Petrochemical Industry Profile," A report to the Petrochemical Energy Group, August 1, 1981.

13 U.S. Department of Energy, Energy Information Administration "Survey of Large Combustors: Report on Alternative-Fuel Burning Capabilities of Large Boilers in 1979," Industrial Energy Consumption, February 12, 1982.

14 See, for example, Federal Energy Regulatory Commission regulations, 18 CFR, Chapter 1, Subchapter A, Paragraph 2.78, "Utilization and Conservation of National Resources - Natural Gas."

15 Davy McKee Corp., Cost Comparison Study, Industrial Size Boilers 10,000 to 400,000 Pound Per Hour, Fluidized Bed Combustion Spreader, Stoker, Pulverized Coal, Oil, Gas, Prepared for the United States Department of Energy, Washington, D.C., DOE Contract EX-77-C-01-2418, Cleveland, Ohio, October, 1979.

16 FERC Docket CP-82, Federal Energy Regulatory Commission, Abbreviated Application of Columbia Gas Transmission Corporation for A Limited Term Certificate of Public Convenience and Necessity Under Section 7(c)

of the Natural Gas Act, as Amended, Authorizing Special Sales Incentive Service and Request for A Temporary Certificate, August 13, 1982.

17 See, for example, comments to the Emission Standards for Engineering Division of the U.S. Environmental Protection Agency, from the Council of Industrial Boiler Owners on the Industrial Boiler New Source Performance Standards of March 29, 1982 and May 14, 1982.

18 T. Devitt, P. Spaite, and L. Gibbs, PEDCo Environmental, Inc., The Population and Characteristics of Industrial/Commercial Boilers, prepared for the U.S. Environmental Protection Agency, Table 2-9, "Distribution of U.S. Water-Tube Industrial Boilers by Capacity and Fuel Type," May, 1979, p. 1[illegible].

19 Chemical Week, "Research is Heating up on Coal-Water Fuels," July 21, 1982.

20 F. Engstrom, Hans Ahlstrom Laboratory, Helsinki, Finland, "Development and Commerical Operation of A Circulating Fluidized Bed Combustion System," The Proceedings of the Sixth International Conference on Fluidized Bed Combustion, Vol. II, August, 1980, pp. 616-621.

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22 Eric J. Oakes, Pyropower Corporation, San Diego, California, and Jorgen Javen and Folke Engstrom, Ahlstrom Company, Finland, Startup and Operating Experience at the Kauttua 22-MW(e) Cogeneration Circulating Fluidized Bed Combustion Plant, Report PCR-107, April, 1982.

26. Utility Flue-Gas Desulfurization: Technology and Costs

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Introduction

Sulfur oxides are air pollutants deleterious to human health and are harmful to vegetation, buildings, and materials. Analyses of numerous epidemiological studies clearly indicate an association between air pollution, as measured by SO_2 concentration, and health effects of varying severities, particularly among the most susceptible elements of the population.

The current environmental driving force for sulfur oxide control is the Clean Air Act, amended in 1977, which created a schedule to decrease SO_2 emissions from power plants and other major sources for both new and existing facilities. The current New Source Performance Standard (NSPS) calls for from 70 to 90 percent SO_2 control for all new coal-fired facilities with the higher level of controls associated with high-sulfur coal. In no cases can emissions of 520 ng/J (1.2 lb $SO_2/10^6$ Btu) be exceeded. This mandates application of control technology to new utility boilers burning both high- and low-sulfur coal. These standards apply to power plants for which construction or modification commenced after September 19, 1978, and are based on commercially available technology taking into account cost. Coal-fired steam generators whose construction or modification commenced after August 17, 1971, but before September 19, 1978, are subject to NSPS requiring maximum SO_2 emissions of 520 ng/J but no percentage removal requirements.

The Clean Air Act amendments indirectly provide for control of existing power plants because State Implementation Plans (SIPs) were required for each state which include a control strategy for ensuring maintenance of the promulgated ambient air quality standards for sulfur oxides and other regulated pollutants. To meet the ambient SO_2 standards, it is necessary to limit the emissions of existing power plants in many of the 247 air quality control regions in many of the states.

Alternatives For Flue Gas Desulfurization

Within the next 5 years, the following options can provide for sulfur oxide control for coal-to-electricity systems: utilization of naturally occurring low-sulfur coal, physical coal cleaning, and flue gas desulfurization (FGD).

In addition, the following emerging technologies are in the development stage and may play a significant role in the post-1990 period: fluidized-bed combustion (atmospheric and pressurized), coal gasification, and coal liquefaction.

Naturally occurring low-sulfur coal is the most straightforward control option. Unfortunately, projected production capacity is limited, and most low-sulfur coal reserves are in the West, far away from Midwestern and Eastern requirements. Utilization of low-sulfur coal east of the Mississippi leads to substantial transportation costs, yielding overall power production costs comparable to the use of FGD with local high-sulfur coals. Also, the current utility NSPS precludes the use of low-sulfur coal without additional sulfur removal in light of the aforementioned 70 to 90 percent control requirement.

Physical coal cleaning utilizes differences in physical properties (e.g., specific gravity) between inorganic pyritic sulfur and other coal constituents. Coals vary widely in the pyritic content (from about 20 to 80 percent of the total sulfur content); organic sulfur and sulfate comprise the remaining portion of the sulfur. Coal cleaning technology is relatively simple and low in both capital cost and annual revenue requirements. Up to 80 percent of the pyritic sulfur can be removed by physical removal techniques. As with naturally occurring low-sulfur coal, coal cleaning cannot generally be utilized alone to meet the current NSPS percentage removal requirements. It should be noted that the combination of coal cleaning and FGD can substantially lower costs compared to FGD alone for certain applications.

In light of the limitations of the low-sulfur coal and coal cleaning options, FGD technology provides the only means of control of new utility sources, inasmuch as it is the only option commercially available by which it is possible to reduce sulfur oxide emissions sufficiently to comply with the current NSPS promulgated under the Clean Air Act. However, for less stringent control requirements for certain existing sources, low sulfur coal and coal cleaning are viable options.

History of FGD

The first commercial application of FGD to power plant sulfur oxide control was in the U.K. in the early 1930s. The Battersea A power plant (228 MW) of the London Power Co., London, U.K., began flue gas washing in 1933. The process utilized wet scrubbing with alkaline Thames River water. The spent liquor was discharged back into the Thames after removal of solids and oxidation. The FGD system operated successfully at up to 95 percent SO_2 removal efficiency until the Battersea A power plant closed down in 1975. A similar FGD system operated on the Battersea B power plant (245 MW) between 1949 and 1969, when FGD operation was temporarily suspended because of adverse effects on the Thames water quality.

The ICI Howden process, also developed in the U.K., was developed to avoid discharging scrubber effluent into the Thames. This technology was the precursor to current lime and limestone wet scrubbing technology in wide use today. The waste sludge produced was barged to the sea for dumping. This process was applied to the Swansea power plant in 1935 and the Fulham power plant in 1937. These systems operated successfully until early World War II, when they were shut down since the steam plumes marked easy targets for enemy bombers.

The next FGD unit was installed at the Electrolytic Zinc Co. in Tasmania in 1949. Tidal water was used there as the absorbent for SO_2 from smelter gas.

In 1952 the first unit of the new oil-fired Bankside Power Station London, U.K., was commissioned. The FGD system is an improved version of the Battersea system, using water from the Thames. This system, which has a 98 percent removal efficiency and capacity of 240 MW, was recently retired.

The 1950s and 1960s were a time of laboratory and pilot plant investigations of new processes. During the 1950s, the Tennessee Valley Authority (TVA) experimented with lime and limestone scrubbing systems, both dry and wet, and dilute acid processes; in Germany the first major carbon adsorption processes were developed. During the 1960s, the magnesium oxide, copper oxide, and sulfite scrubbing processes were investigated.

Lime/limestone processes were installed in 1964 on an iron ore sintering plant in the USSR and on a large sulfuric acid plant in Japan in 1966.

In 1966 Combustion Engineering developed a process which injected dry limestone into the boiler followed by a wet scrubbing operation. In the U.S.,

the first commercial system of this type was installed in 1968; there were five utility installations of this system by 1972. Because of major problems associated with dry limestone injection, these systems proved inadequate. Problems included plugging (especially of the spaces between boiler tubes), low SO_2 removal, and increased particle emissions from the electrostatic precipitators. The five installations are now either shut down or converted to other types of systems. U.S. lime and limestone FGD technology was substantially improved and advanced via the EPA large pilot facility at TVA's Shawnee Steam Plant. This facility identified scrubber configurations and operating parameters yielding reliable and efficient operation.

FGD has been widely used in Japan and is considered an accomplished technology. Over 1,300 commercial FGD units have been operated to treat gases generated from various processes including many oil-fired boilers. FGD processes treat a total capacity of over 120,000,000 Nm^3/hr (40,000 MW equivalent) to remove 85-90 percent of SO_2. The principal by-products are gypsum, sodium sulfite, and sulfuric acid.

The total capacity of coal-fired utility boilers in Japan is now 4,300 MW (3.7 percent of total utility power) and is expected to reach 10,000 MW (5.6 percent) in 1985 and 22,000 MW (10 percent) in 1990. Several coal-fired industrial boilers also may be constructed in the future. All of these boilers will apply FGD to reduce SO_2 emissions.

Recently, in the United States, dry scrubbing systems employing spray dryers and producing a dry disposable waste are becoming an important part of the U.S. market. Pilot testing and early commercial operation have indicated that such systems can achieve up to 90 percent sulfur control (although most are designed for 70-80 percent control) at costs substantially lower than wet systems for low to moderate sulfur coals.

Description of FGD Systems

FGD systems can be classified in two general categories: (1) systems in which the sulfur product generated through a scrubbing or adsorption operation is disposed of as waste (throwaway product systems) and (2) those in which the sulfur product, such as sulfuric acid, is marketed (salable product systems). Although over 50 processes have been tested at bench scale or larger, the number of commercially significant processes is considerably smaller. The follow-

ing commercially offered throwaway and salable product systems are considered the most important for near-term (through 1990) SO_2 control:

1. Throwaway product systems - lime and limestone scrubbing (both sludge and gypsum variations) and dual (double) alkali.
2. Salable product systems - magnesium oxide scrubbing and Wellman-Lord (sodium sulfite scrubbing).

Other potentially important systems which are close to commercialization include dry scrubbing, seawater scrubbing, carbon adsorption and copper oxide adsorption. Tables 1, 2, and 3 categorize the important systems as "throwaway;" salable product, gypsum; and salable product, regenerative, respectively, and summarize their commercial status and principles of operation.

A typical lime or limestone wet scrubbing throwaway FGD process associated with a coal-fired utility boiler, shown schematically in Figure 1, illustrates the interrelationships between the various major system components. The major components shown are: an electrostatic precipitator for upstream dry particle collection, a spray tower absorber (scrubber), a thickener, and filter. There are many variations on this basic scheme.

Growth of U.S. Utility Application

Currently there are 96 FGD units controlling more than 36,000 MW of generating capacity at U.S. utilities. Projecting into the future, there will be a total of 221 units, based on currently operational, under construction, and planned units with relatively firm commitments,to control about 107,000 MW of coal-fired electric generating capacity by the turn of the century. The projected growth of utility FGD application, as a function of the year of the estimate, is shown in Figure 2. Since planned units are based on known commitments, the estimates are conservative. (Capacity is expressed in this paper as Total Controlled Capacity (TCC) or Equivalent Scrubbed Capacity (ESC).)

At the end of 1980 about 40 percent of the nation's electric generating capacity was coal-fired. By the end of the century, the figure is expected to be 45 percent of higher. Currently, about 14 percent of our coal-fired generating capacity is controlled by FGD; by the end of the century, that figure is conservatively estimated to approach 30 percent, with an

TABLE 1. SUMMARY DESCRIPTION OF FGD PROCESSES - "THROWAWAY" CATEGORY

FGD process (year of first use)	Primary reagent	Product of disposal	Operating principles	Present status
Limestone/sludge[a] (1933)	$CaCO_3$	$CaSO_3/CaSO_4$ wet sludge	Flue gases scrubbed with limestone slurry; SO_2 reacts to form insoluble Ca compounds which are separated and partly dewatered for disposal.	Commercial operation (coal and oil), principally in U.S.
Lime/sludge[a] (1972)	CaO	$CaSO_3/CaSO_4$ wet sludge	Flue gases scrubbed with slurry of hydrated lime; SO_2 reacts to form insoluble Ca compounds which are separated and partly dewatered for disposal.	Commercial operation (coal and oil), principally in U.S.
Dual (double) alkali/sludge (1974)	NaOH or Na_2CO_3 and CaO or $CaCO_3$	$CaSO_3/CaSO_4$ wet sludge	Flue gases scrubbed with alkaline Na compounds in solution; used solution regenerated with lime or limestone in separate reactor and to form insoluble Ca compounds which are separated and partly dewatered for disposal.	Recent commercial operation on coal-fired boilers in U.S.
Seawater scrubbing (1975)	Seawater	Dilute sulfite solution	Flue gases scrubbed with seawater on a once-through system and discharged back to sea.	Commercial small-scale operation on oil-fired boilers in Norway.
Dry scrubbing	CaO or sodium alkali	$CaSO_3$ or Na_2SO_3	Flue gases are treated in a spray dryer where alkali slurry or solution spray absorbs the SO_2, cools the flue gases, and produces a dry waste material collected in a downstream baghouse or electrostatic precipitator.	Several industrial and utility applications in construction and early operational phase currently applicable to coals with low to moderate sulfur content.
Sodium carbonate scrubbing	Na_2CO_3 or other alkali sodium salt	Na_2SO_3/ Na_2SO_4	Flue gases are treated in scrubber with sodium salt solution; spent liquor generally disposed of in evaporation ponds in arid areas.	Commercial in Western U.S. in arid areas where evaporation ponds feasible.

[a]Important variations of these processes are lime/alkaline fly ash and limestone/alkaline fly ash which utilize natural alkalinity in certain coals to greatly minimize reagent requirements.

TABLE 2. SUMMARY DESCRIPTION OF FGD PROCESSES - SALABLE PRODUCT, GYPSUM CATEGORY

FGD process (year of first use)	Primary reagent	Product of disposal	Operating principles	Present status
Limestone/gypsum (1973)	$CaCO_3$	Gypsum	Flue gases scrubbed with limestone slurry; resulting calcium-sulfur compounds are air-oxidized to gypsum, separated, and dewatered.	Commercial operation (coal and oil), principally in Japan.
Lime/gypsum (1964)	CaO	Gypsum	Flue gases scrubbed with slurry of hydrated lime; resulting calcium-sulfur compounds are air-oxidized to gypsum, separated, and dewatered.	Commercial operation (coal and oil), principally in Japan, but also recently in West Germany.
Double (dual) alkali/gypsum (1973)	NaOH or Na_2CO_3 and CaO or $CaCO_3$	Gypsum	Flue gases scrubbed with alkaline Na compounds in solution; used solution regenerated with lime or limestone in separate reactor and the insoluble calcium-sulfur compounds then air-oxidized to gypsum, separated, and dewatered.	Commercial operation on oil-fired boilers in Japan.
Dilute sulfuric acid/gypsum (Chiyoda) (1972)	H_2SO_4 and $CaCO_3$	Gypsum	Flue gases are scrubbed with dilute sulfuric acid containing ferric ion catalyst; air oxidation produces more sulfuric acid when bled off and neutralized with limestone; the gypsum is separated and dewatered.	Commercial operation on oil-fired boilers in Japan.

TABLE 3. SUMMARY DESCRIPTION OF FGD PROCESSES - SALABLE PRODUCT, REGENERATIVE CATEGORY

FGD process (year of first use)	Primary reagent	Product of disposal	Operating principles	Present status
Sodium sulfite (Wellman-Lord) (1971)	Na_2CO_3	SO_2	Flue gases are scrubbed with sodium sulfite solution and the resulting sodium bisulfite is thermally regenerated to sodium sulfite and SO_2; the SO_2 is then further treated to marketable products.	Commercial operation on oil-fired boilers in Japan; recent commercial application of coal-fired boilers in U.S.A.; also on chemical/ oil refinery plants.
Magnesium oxide (1972)	MgO	SO_2	Flue gases scrubbed with slurry of hydrated magnesium oxide; insoluble magnesium sulfite is separated and calcined for recycle of MgO and regeneration of SO_2 for further treatment.	Commercial operation on oil-fired boilers in Japan; demonstration plant on coal-fired boiler in U.S.
Carbon absorption (1974)	C	SO_2	SO_2 from flue gases is absorbed on active carbon which is then regenerated thermally, releasing SO_2 for recovery.	Demonstration.
Copper oxide (Shell) (1973)	CuO	SO_2	SO_2 from flue gases is absorbed on copper oxide coated alumina; this is then treated chemically to regenerate the absorber and produce SO_2 for recovery.	Demonstration.

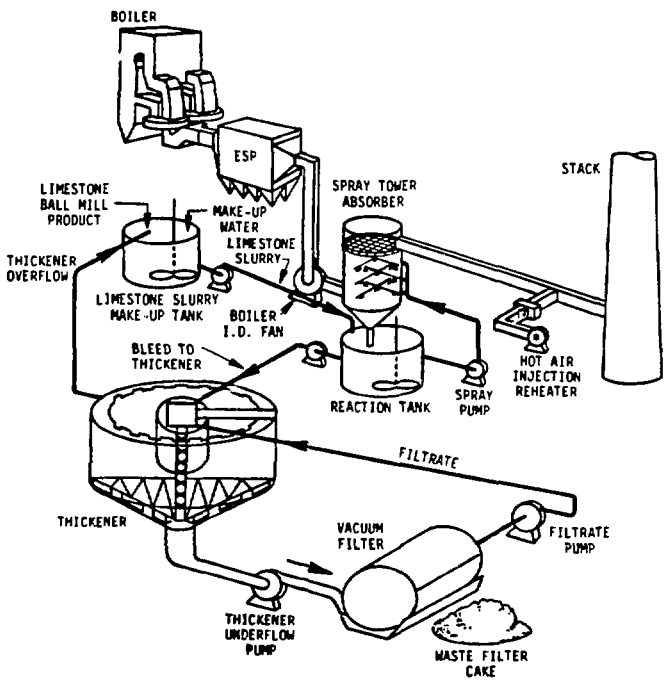


Figure 1. Typical lime or limestone wet scrubbing throwaway FGD process.

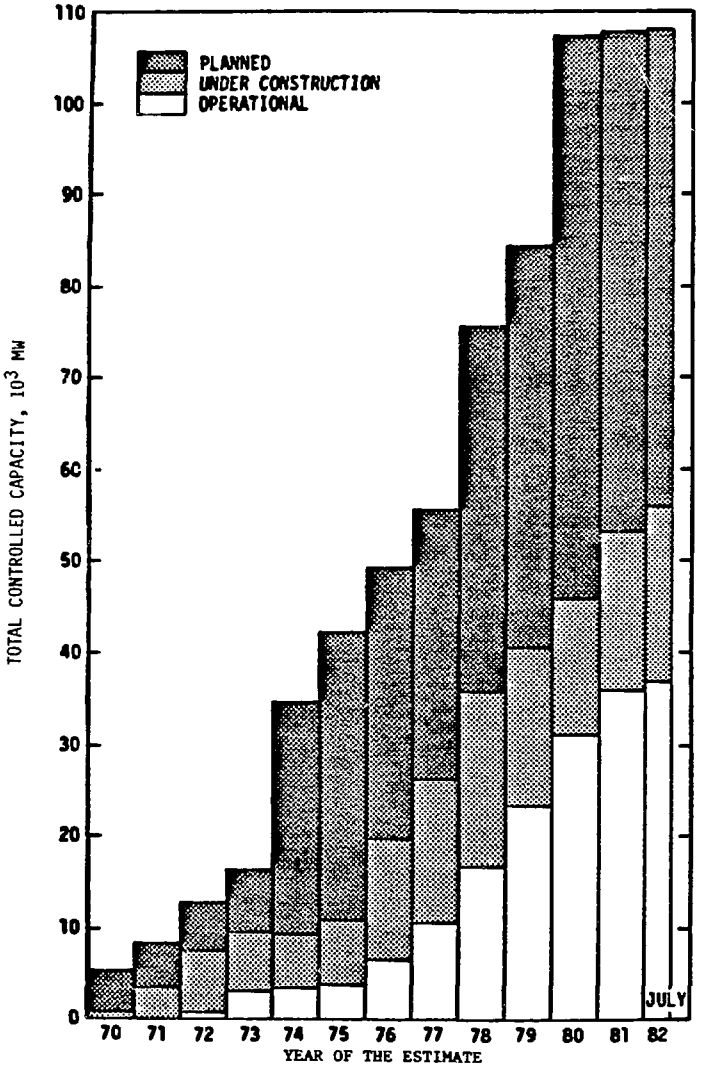


Figure 2. Projected utility FGD capacity.

assumed total growth in generating capacity of 35 percent over the 20-year period.[1] (References at end of paper.)

EPA Utility FGD Survey

Since 1974, EPA's Industrial Environmental Research Laboratory at Research Triangle Park, North Carolina (IERL-RTP) has employed PEDCo Environmental, Inc. under contract to conduct a data gathering survey of utility FGD systems. PEDCo's function is to gather and systematically tabulate and file design, performance, and cost data on utility FGD systems inoperation, under construction, and planned.

Design data include information on the boiler, stack, fans, pumps, tanks, materials of construction, coal composition, removal efficiency, particulate matter control systems, waste disposal, by-product utilization, and other items of interest. Performance data include dependability of the system, problems and solutions, and pollutant removal. Data on real system capital cost and annual revenue requirements are also gathered in the survey, and are presented as "reported" and "adjusted" costs. The "reported" costs are those submitted by the utilities to PEDCo. The "adjusted" costs are the results of an attempt to reduce all utility-reported costs to a relatively comparable basis. The adjustment procedure is described in each update of the EPA Utility FGD Survey.[1]

The information in the survey is supplied voluntarily by utilities, process suppliers and developers, regulatory groups, and others. As such, it is subject to errors in transmission of data or in the lack of uniformity in reporting the data throughout the industry. With these qualifications, it is probably the best comprehensive statistical overview of the status of utility FGD applications that exists. Most of the data presented are taken form the survey.

All of the collected information is stored in a computerized data base called the "Flue Gas Desulfurization Informatioin System" (FGDIS).[2] The FGDIS is accessible to the general public through the National Technical Information Service (NTIS) in Springfield, VA. After obtaining a valid user ID and password, the system can be accessed via a computer terminal and a telephone modem by dialing a local telephone number. The user is charged for the computer time by NTIS.

U.S. Trends in Selection of FGD Processes

The U.S. utility FGD systems are summarized by process type and status category in Table 4, based on FGDIS data.

The vast majority of utility FGD systems in the U.S. are the throwaway variety. Of the presently known, operational, under construction, and planned units, for which a process has been selected, about 95 percent are throwaway and 5 percent are salable procuct processes. In the operational status, 93 percent are throwaway and 7 percent salable product processes; in the under construction status, 94 percent are throwaway and 6 percent are salable product processes. There are no additional salable product processes in the planned status.[2]

The fact that throwaway systems predominate in utility applications is probably due to more favorable economics and process simplicity. The salable product processes, although more environmentally aesthetic, require much higher capital investment. With current high interest rates, this also translates into higher annual revenue requirements. These facts apparently override the cost savings for waste disposal and by-product credits for the salable product processes in most cases at present. If waste disposal becomes inordinately more expensive, and the value of sulfur products increases significantly, in the future, salable product processes may be more economically favored.

The projected capacity of utility FGD processes in operation at the end of each 2-year period is given by process type in Figure 3. The trend indicated, based on known orders for utility FGD systems, is toward wet limestone throwaway systems with lime throwaway systems maintaining a large market share and dry systems becoming increasingly important.

The trend toward dry systems is indicated in Table 5. Although this is an emerging technology, it is expected that dry systems will be less costly to install and operate than wet systems; however, their application may be limited to low- and medium-sulfur coals if the current NSPS for utility boilers (requiring 70 to 90 percent SO_2 removal or more) is to be achieved. The anticipated and real economic benefits of these systems over the wet systems may diminish as more experience is gained with operating systems; costs for wet systems have increased after operating experience was factored into the design of newer systems.

TABLE 4. SUMMARY OF UTILITY FGD SYSTEMS BY PROCESS AND STATUS CATEGORY

Process	Total		Status category: Operational		Under construction		Contract awarded		Planned	
	No.	MW	No.	MW	No.	MW	No.	MW	No.	MW
Aqueous carbonate/spray drying	1	100	1	100	0	0	0	0	0	0
Citrate	1	60	1	60	0	0	0	0	0	0
Lime/gypsum	1	65	0	0	1	65	0	0	0	0
Limestone/gypsum	1	166	0	0	1	166	0	0	0	0
Lime/limestone/gypsum	1	475	0	0	1	475	0	0	0	0
Magnesium oxide	3	724	1	240	2	484	0	0	0	0
Wellman-Lord	7	1,959	7	1,959	0	0	0	0	0	0
Subtotal - Salable product	15	3,549	10	2,359	5	1,190	0	0	0	0
Dual alkali	6	2,288	3	1,181	2	842	1	265	0	0
Lime	32	14,145	24	9,680	5	2,805	1	650	2	1,010
Limestone	81	38,632	38	13,920	19	9,362	14	10,060	10	5,290
Limestone/alkaline fly ash	2	1,500	2	1,500	0	0	0	0	0	0
Lime/alkaline fly ash	11	4,238	9	2,838	2	1,400	0	0	0	0
Lime or limestone (test unit)	2	20	2	20	0	0	0	0	0	0
Lime or sodium carbonate (test unit)	1	100	1	100	0	0	0	0	0	0
Lime/spray drying	13	4,263	1	110	9	2,893	3	1,260	0	0
Process not selected[a]	6	3,530	0	0	0	0	0	0	6	3,530
Sodium carbonate (once through, wet)	9	3,155	5	1,255	1	250	0	0	3	1,650
Sodium carbonate/spray drying	1	440	1	440	0	0	0	0	0	0
Subtotal - Throwaway product	164	72,311	86	31,044	38	17,552	19	12,235	21	11,480
Totals	179	75,860	96	33,403	43	18,742	19	12,235	21	11,480
Salable product process % of total MW		5		7		6		0		0

[a] A process has not been selected for these throwaway product FGD systems. An additional 42 units are undecided (with respect to salable or throwaway product) and are not included in this table.

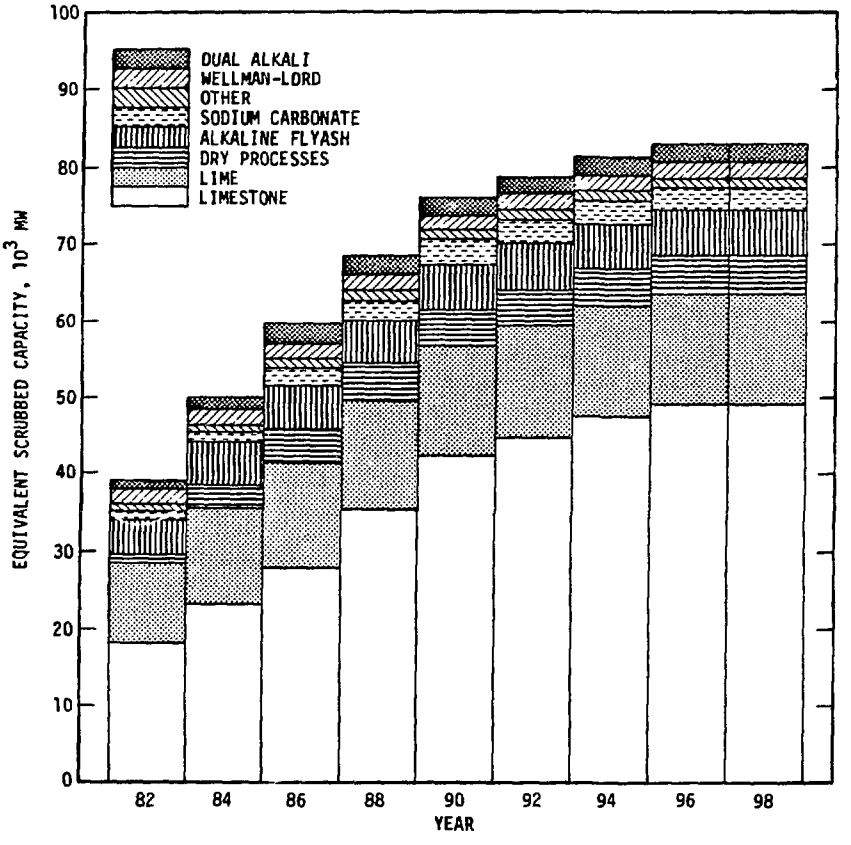


Figure 3. Projected utility FGD capacity (where process has been selected).

TABLE 5. COMMITTED FGD CAPACITY - WET VS DRY PROCESSES

	FGD capacity, MW			
	Operational	Under construction	Contract awarded	Total
Wet	32,653	15,849	10,060	58,562
Dry	750	2,893	1,260	4,903
Totals	33,403	18,742	11,320	63,465
% Dry	2	15	11	8

Energy Consumption

One frequently cited disadvantage of an FGD system is that it reduces the output of energy produced by a power plant. Although this is a fact, the energy consumption has been frequently overstated.

Values of energy consumption for some of the operational utility FGD systems are tabulated in Table 6 from the FGDIS data base.

TABLE 6.
ENERGY CONSUMPTION FOR OPERATIONAL FGD SYSTEMS[a,b]

Process	Range	Average
Dual alkali	0.8 - 2.4	1.4
Line	1.3 - 4.1	2.3
Limestone	0.9 - 5.2	2.7
Sodium carbonate (once-through, wet)	0.2 - 1.5	0.8
Wellman-Lord	3.6 - 4.6	4.0

[a] Excluding flue gas reheat.
[b] Electrical energy consumption of the FGD installation as a percentage of gross unit generating capacity.

Generally, the regenerable salable product systems require substantially more input energy for the regeneration step.

Waste Disposal

An area of great interest in the throwaway systems is the waste disposal method. Typical sludge from a wet FGD system is a mixture of calcium sulfite and sulfate containing a certain amount of fly ash and about 50 percent by weight of free water. Without stabilization it might have a consistency comparable to wet clay or toothpaste.

Disposal is generally by ponding or landfilling. Ponds may be lined with a clay bottom, a polymer or rubberized sheet bottom (although this is very costly and generally not used), or unlined. Lining prevents percolation into the groundwater or occluded sludge liquors containing a vast variety of chemical constituents found in the fly ash or generated by reactions in the FDG system. Sludge is generally sluiced to the pond, the waste solids settle, and supernate pond water is returned to the FGD system for reuse. Landfilling is generally accomplished by trucking or

otherwise transporting the waste to a landfill site after some form of treatment.

Treatment may include forced oxidation, fixation, and/or stabilization. Forced oxidation involves reacting the calcium sulfite/sulfate mixture with oxygen from the air as a separate step in the FGD process. This converts most of the waste to gypsum which can be dewatered to 80-90 percent solids using thickeners, filters, and/or centrifuges, so that the waste is mechanically stable for landfill. Stabilization might involve mixing dry fly ash with the wet sludge to produce a more mechanically stable landfill. The quantities of FGD waste (dry basis) and fly ash in the mixture are generally of the same order of magnitude. Fixation generally means achieving mechanical stability through pozzolanic chemical reaction. Again the wet solids might be mixed with an equal amount of dry fly ash and about 3-5 percent by weight of lime. This mixture then undergoes pozzolanic reactions that make the waste more mechanically stable and less permeable to rainwater, thus locking in many of the soluble constituents of the sludge liquor. Permeability is further reduced by mechanical compaction at the disposal site. Another fixation process that has been used involves mixing fly ash and other fixation chemicals with the FGD wastes and sluicing the mixture to a pond. The mixture of solids then settles to the bottom of the pond and undergoes pozzolanic reactions (sets up) underwater. Several companies offer sludge fixation and stabilization processes. Disposal characteristics for the utility systems currently operational and under construction are given in Table 7.

The table shows a trend toward landfill vs ponding for the units scheduled for future operation, judging by a comparison of the currently operational and under construction unit. No definite treatment trend is indicated in the type of treatment used. Treatment method (or the lack of it) is dictated by site-specific economic and local regulatory or permitting requirements.

Particulate Matter Control

Particulate matter control must be considered along with the installation of a utility FGD system. The three methods currently considered are:

- Electrostatic Precipitator (ESP).
- Fabric Filter (FF).
- Wet Scrubbing.

TABLE 7. DISPOSAL CHARACTERISTICS OF UTILITY FGD SYSTEMS

Disposal characteristics	Operational		Under construction	
	No.	MW	No.	MW
Sludge processing type				
Untreated	24	6,495	4	1,922
Treated				
Forced oxidation	14	7,078	7	3,890
Fixation	19	9,314	7	3,004
Stabilization	16	6,036	4	2,017
Sludge disposal method				
Landfill	39	13,597	24	9,557
Pond	48	17,291	7	3,082

Dry collection of fly ash upstream of wet FGD system may be desirable since dry fly ash may be needed to fix or stabilize the waste. collecting fly ash in a wet scrubbing process can create wet/dry interface scaling and fouling problems due to pozzolanic reaction with calcium compounds in the scrubber. In addition, fly ash tends to be very erosive in wet scrubbing systems, thus causing more maintenance problems.

On the other hand, fly ash may contain alkaline compounds such as CaO, MgO, and Na_2O which assist in SO_2 removal, thus giving rise to design for wet scrubbing of particulate matter in conjunction with SO_2 removal. When wet scrubbing is employed, the design usually involves a two-stage scrubbing system in which particulate matter is removed in the first stage and SO_2 is removed primarily in the second stage. To remove a large fraction of particulate matter, especially the finer particles, a high gas pressure drop is required, and thus an energy penalty results due to higher fan energy requirements. The methods used and planned for future use in utility FGD are tabulated in Table 8. A clear preference for ESPs is shown. Wet scrubbing for particle control, although significant in the currently operational units shows a clear decline in preference based on known plans for future units (the NSPS requires more stringent control than can reasonably be achieved by wet scrubbing alone).

Dependability

During the past decade, as the number of utility FGD systems has increased dramatically, we have monitored their dependability via the Utility FGD Survey and FGDIS.

There are many ways to measure and express a unit's dependability. None of them provides a completely precise measure. The FGDIS uses four indices[1,2] to characterize dependability. For this paper we have selected to utilize availability as a measure of dependability. Availability is defined as the hours the FGD system is available for operation (whether operated or not) divided by hours in the period, expressed as a percentage. This parameter can, in some cases, overestimate the viability of the FGD system since, during periods in which it is decided not to use the FGD system and during boiler downtime. This definition assumes the FGD unit is available even though it could have developed problems during such periods. There other parameters fre-

TABLE 8. SUMMARY OF PARTICLE EMISSION CONTROL SELECTION

	Operational		Under construction		Planned units	
	No.	MW	No.	MW	No.	MW
Electrostatic precipitator	60	21,823	26	11,731	25	16,580
Fabric filter	3	650	11	3,458	11	5,228
Wet scrubbing	23	7,371	3	1,650	0	0
Electrostatic precipitator and wet scrubbing	10	3,559	3	1,903	0	0
Total	96	33,403	43	18,742	36	21,808

quently used, operability, reliability, and utilization, are defined in the EPA Utility FGD Survey.[2]

The average availabilities from start-up to the present, and for the latest 12-months period, are plotted against the year in which the unit was started up for both high- and low-sulfur coal units in Figures 4 and 5, respectively. High-sulfur coal was arbitrarily defined as having greater than 2 percent sulfur by weight. Only commercial (nontest units) required to achieve a minimum of 520 ng.J (1.2 lb/10^6 Btu), SO_2 emissions, and which had at least 2 years of operation, were plotted, using data from the FGDIS.

In the vast majority of the units plotted, the average availability was higher during the latest 12-months period than during the whole period of operation. As might be expected, availability improves after a period of shakedown or "debugging" and the operators gain experience in operating the system; at least, that's our interpretation of the data. In addition, it appears that most of the availability figures for the latest 12-month period are in the 80 to 100 percent range.

Using the FGDIS, a categorical tabulation of domestic utility FGD system dependability by process was developed and is presented in Table 9. The table presents the number of operating FGD systems, number currently reporting availability, and average availability for the last 12-month period by process, FGD system age, application (new vs retrofit), and coal sufur content. The table shows that, except for the citrate process which is in an early stage of commercial development, most of the "second generation" FGD processes have better availability performance than the lime and limestone throwaway processes which are the mainstays of the industry; however, in perspective, there are much more data and experience with the lime and limestone processes. As indicated previously, the trend toward increasing availability with age of the system is evident. There appears to be no clear trend with respect to availability vs new or retrofit application. Availability appears to be better for low-sulfur coal units than for medium- or high-sulfur coal units. In the past, FGD critics frequently stated that high availability was hard to achieve with high-sulfur coal. These data show, however, that availabilities for high-sulfur coal units are now intermediate between low- and medium-sulfur coal unit availabilities achieved by dual alkali systesm in high sulfur coal applications, and to the general incrase of availability with age of the system (this assumes more of the high-sulfur coal units are older).

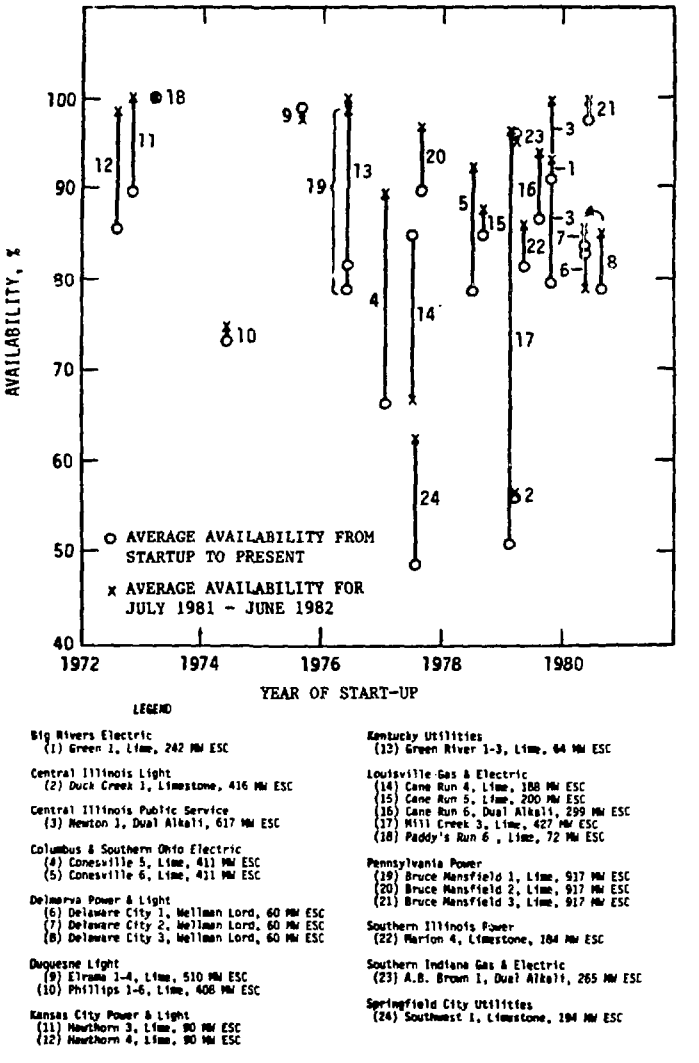
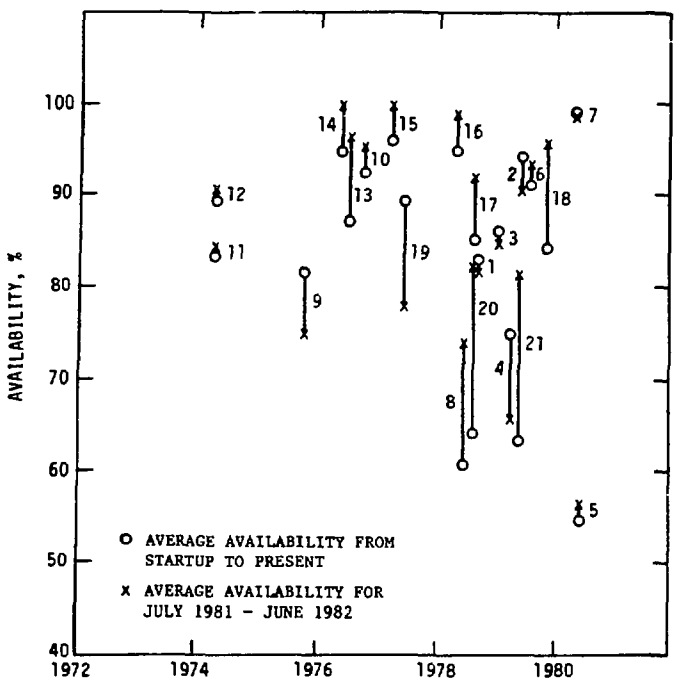


Figure 4. Availability for high-sulfur coal utility FGD units.



LEGEND

Alabama Electric
(1) Tombigbee 2, Limestone, 179MW ESC
(2) Tombigbee 3, Limestone, 179MW ESC

Arizona Electric Power
(3) Apache 2, Limestone, 98 MW ESC
(4) Apache 3, Limestone, 98 MW ESC

Colorado Ute Electric
(5) Craig 2, Limestone, 410 MW ESC

Cooperative Power Association
(6) Coal Creek 1, Lime/Alkaline Flyash, 327 MW ESC

Minnesota Power & Light
(7) Clay Boswell 4, Lime/Alkaline Flyash, 475 MW ESC

Nonkota Power
(8) Milton R. Young B, Lime/Alkaline Flyash, 374 MW ESC

Montana Power
(9) Colstrip 1, Lime/Alkaline Flyash, 360 MW ESC
(10) Colstrip 2, Lime/Alkaline Flyash, 360 MW ESC

Nevada Power
(11) Reid Gardner 1, Sodium Carbonate, 125 MW ESC
(12) Reid Gardner 2, Sodium Carbonate, 125 MW ESC
(13) Reid Gardner 3, Sodium Carbonate, 125 MW ESC

Northern States Power
(14) Sherburne 1, Limestone/Alkaline Flyash, 740 MW ESC
(15) Sherburne 2, Limestone/Alkaline Flyash, 740 MW ESC

Public Service of New Mexico
(16) San Juan 1, Wellman Lord, 361 MW ESC
(17) San Juan 2, Wellman Lord, 350 MW ESC
(18) San Juan 3, Wellman Lord, 534 MW ESC

South Carolina Public Service
(19) Winyah 2, Limestone, 140 MW ESC

South Mississippi Electric Power
(20) R.D. Morrow, Sr. 1, Limestone, 124 MW ESC
(21) R.D. Morrow, Sr. 2, Limestone, 124 MW ESC

Figure 5. Availability for low-sulfur coal utility FGD units.

TABLE 9. CATEGORICAL SUMMARY OF DOMESTIC FGD SYSTEM AVAILABILITIES

Category	No. of operating FGD systems	No. of FGD systems currently reporting availability	Average availability for July 1981 - June 1982
Process			
Limestone/alkaline fly ash	2	2	100.00
Dual alkali	3	3	96.92
Sodium carbonate	5	4	90.49
Wellman Lord	7	7	89.14
Lime/alkaline fly ash	9	6	86.85
Lime	24	23	84.14
Limestone	38	24	75.56
Citrate	1	1	14.90
FGD system age			
0 through 2 years	26	12	80.38
Greater than 2 years through 4 years	33	28	80.47
Greater than 4 years	37	30	86.96
Application			
New	62	47	82.38
Retrofit	34	23	82.22
Coal sulfur content			
Low (<1.0% S)	45	32	86.15
Medium (1.0 to 3.0% S)	24	14	77.31
High (>3.0% S)	30	27	81.04

FGD Costs

The subject of FGD costs has generated much confusion and controversy. This understandable when one considers the variety of processes, coal types, and site specific conditions, as well as the differences and inaccuracies in various cost estimating techniques.

Costs are generally categorized as capital costs and annual revenue requirements. The former include: direct investment, indirect investment, land costs, working capital, contingency, and other capital charges including interest during construction and allowance for start-up and modifications. The latter include: direct costs for raw materials, labor, supervision, utilities, and maintenance; and indirect costs for capital charges and overheads. The annual revenue requirements figure is representative of the cost to the consumer and is expressed as a unit cost of electrical energy (e.g., mills/kWh). The capital cost is more a concern of the utility industry particularly when interest rates are high, in that it represents a capital expenditure which must be paid for with revenues raised through the sale of stocks or bonds or other means of capitalization.

Two basic approaches to estimating costs for FGD systems are:

1. Gathering data on actual FGD systems and making adjustments to express these on a relatively common basis.
2. Establishing a set of design and economic premises and arriving at a cost estimate through the use of an appropriate engineering/economic mathematical model, to design the system.

We have used both approaches to arrive at categorical utility FGD capital costs and annual revenue requirements. The first approach has been used by PEDCo Environmental, Inc. in the EPA Utility FGD Survey[1] and in the FGDIS.[2] The second approach has been used by TVA in several cost analysis projects under an interagency agreement with EPA. Since the actual systems were installed under conditions that never exactly fit the TVA design and economic premises, and several systems had certain unique site specific circumstances, one would not expect perfect agreement between two approaches; however, the authors believe agreement within about 30 percent would be considered good considering the limitations of the systems.

Adjusted Actual Costs

In the first approach PEDCo has adjusted the costs of all operational utility FGD systems, for which the respective utility companies have reported data, to a common basis using a cost adjustment procedure that focuses on the following items:

- All capital costs are adjusted to mid-1981 dollars using appropriate escalation factors.
- Gross unit capacity is used to express all FGD capital expenditures because the capital requirements of an FGD system is dependent on actual boiler size before derating for auxiliary and air quality control power requirements.
- Particulate matter control costs are deducted.
- The capital costs associated with the modification, or installation of equipment not part of the FGD system but needed for its proper functioning, are included (e.g., stack lining, modification to existing ductwork or fans).
- Indirect charges are adjusted to provide adequate funds for engineering, field expenses, legal expenses, insurance, interest during construction, allowance for start-up, taxes, and contingency expenditures.
- All annual revenue requirements, represented in mills/kilwat-hour (mills/kWh), are expressed in terms of net megawatts (MW).
- Net unit capacity is used to express all FGD annual revenue requirements.
- All non-labor annual revenue requirements are adjusted to a common 65 percent capacity factor.
- Replacement power costs for retrofitted FGD systems are not included since only a few utilities reported such costs and these were presented using a variety of methods.
- Sludge disposal costs are adjusted to reflect the costs of sulfur dioxide waste disposal only (i.e., excluding fly ash disposal except where usable as sludge stablizing agent) and to provide for disposal over the anticipated lifetime of the FGD system.
- A 30-year life is assumed for all process and economic considerations for all new systems that were installed for the life of the unit. A 20-year life is assumed for all process and economic considerations for retrofit systems that were installed for the remaining portion of the life of the unit.
- Regeneration and by-product recovery facility costs are added for those regenerable systems not reporting such costs.

A tabulation of the adjusted capital costs and annual revenue requirements for the operational utility FGD systems in the FGDIS data base is given in Table 10.

A categorical summary of these results, including a range and average cost regardless of the unit's capacity or coal sulfur content, is given in Table 11.

Design Model Costs

In one example of the design model approach to FGD cost estimating, TVA has estimated the cost for nine FGD processes in the "NATO-CCMS Flue Gas Desulfurization Pilot Study.[3] The basis of the economic evaluation is an FGD system for a new midwestern U.S. 500 MW power plant. The FGD system is designed for removal of 90 percent of the SO_2 in the flue gas. Six fuels consisting of bituminous coal, lignite, and oil were evaluated. Scaling procedures were utilized for projection of costs for other conditions such as different power plant size and coal sulfur content. Models were utilized for nine flue gas desulfurization processes deemed to be important on a world-wide basis. The design FGD process is assumed to have a 30-year lifetime of 117,500 operating hours and to operate 6,000 hours in the first year. Fly ash removal by electrostatic precipitator upstream of the FGD system is not included in the FGD cost.

The economic premises are based on U.S. regulated utility economics and financing. The cost estimates consist of capital costs for construction of the FGD system and annual revenue requirements for the first year of operation. The capital costs consist of all direct and indirect costs for equipment, land, materials, labor, fees, services, and other construction costs required to install the FGD system. Annual revenue requirements consist of all raw material, labor, utility, and other conversion costs and indirect costs such as capital charges, taxes, and overheads. By-product sales for processes producing elemental sulfur, sulfuric acid, gypsum, and sodium sulfate are included as credits. The technical design premises for the nine processes are summarized in Table 12.

Process and economic evaluation results are shown for a variety of size and fuel variations in Table 13. Accuracy ranges for the 500 MW base case investment and annual revenue requirements are shown in Figures 6 and 7. All capital investments are mid-1979 U.S. dollars; all revenue requirements are mid-1980 U.S. dollars.

TABLE 10. ADJUSTED CAPITAL COSTS AND ANNUAL REVENUE REQUIREMENTS FROM THE FGDIS

Utility/unit	Process type	Coal sulfur content, %	Equivalent scrubbed capacity, MW	Adjusted capital cost,[a] $/kW	Adjusted annual cost,[a] mills/kWh
Alabama Electric					
Tombigbee 2	Limestone	1.61	179	38.30	3.18
Tombigbee 3	Limestone	1.61	179	38.30	3.18
Arizona Electric Power					
Apache 2	Limestone	0.50	98	67.50	3.75
Apache 3	Limestone	0.50	98	59.80	3.75
Arizona Public Service					
Cholla 1	Limestone	0.50	119	81.30	4.79
Cholla 2	Limestone	0.50	285	162.10	8.22
Central Illinois Light					
Duck Creek 1	Lime	3.40	416	132.20	5.78
Central Illinois Public Service					
Newton 1	Dual alkali	3.00	617	263.90	13.94
Colorado Ute Electric					
Craig 1	Limestone	0.45	410	105.90	5.33
Craig 2	Limestone	0.45	410	90.30	4.56
Columbus & Southern Ohio Electric					
Conesville 5	Lime	4.67	411	99.40	6.78
Conesville 6	Lime	4.67	411	99.40	6.78
Cooperative Power Association					
Coal Creek 1	Lime/alkaline fly ash	0.63	327	52.50	2.99
Coal Creek 2	Lime/alkaline fly ash	0.63	327	52.50	2.99

(continued)

TABLE 10. ADJUSTED CAPITAL COSTS AND ANNUAL REVENUE REQUIREMENTS FROM THE FGDIS (Continued)

Utility/unit	Process type	Coal sulfur content, %	Equivalent scrubbed capacity, MW	Adjusted capital cost,[a] $/kW	Adjusted annual cost,[a] mills/kWh
Duquesne Light					
Elrama 1-4	Lime	2.05	510	187.80	12.89
Phillips 1-6	Lime	2.05	408	210.00	17.65
Indianapolis Power & Light					
Petersburg 3	Limestone	3.25	532	162.10	9.74
Kansas City Power & Light					
Hawthorne 3	Lime	2.05	90	62.80	5.25
Hawthorne 4	Lime	2.05	90	62.80	5.25
La Cygne 1	Lime/alkaline limestone	5.39	874	100.10	11.29
Kansas Power & Light					
Jeffrey 1	Limestone	0.32	540	55.90	2.42
Jeffrey 2	Limestone	0.30	490	41.20	1.65
Kentucky Utilities					
Green River 1-3	Lime	2.50	64	117.80	10.99
Louisville Gas & Electric					
Cane Run 4	Lime	3.75	188	115.20	6.20
Cane Run 5	Lime	3.75	200	102.40	5.30
Cane Run 6	Dual alkali	4.80	299	87.80	7.23
Mill Creek 1	Lime	3.75	358	60.40	4.26
Mill Creek 3	Lime	3.87	427	66.00	4.03
Paddy's Run 6	Lime	3.70	72	133.00	12.25
Minnesota Power and Light					
Clay Boswell 4	Lime/alkaline fly ash	0.94	475	184.40	14.09

(continued)

TABLE 10. ADJUSTED CAPITAL COSTS AND ANNUAL REVENUE REQUIREMENTS FROM THE FGDIS (Continued)

Utility/unit	Process type	Coal sulfur content, %	Equivalent scrubbed capacity, MW	Adjusted capital cost,[a] $/kW	Adjusted annual cost,[a] mills/kWh
Minnkota Power					
Milton R. Young 2	Lime/alkaline fly ash	0.60	374	155.70	6.44
Monongahela Power					
Pleasants 1	Lime	3.00	626	152.90	7.94
Pleasants 2	Lime	3.00	626	152.90	7.94
Montana Power					
Colstrip 1	Lime/alkaline fly ash	0.78	360	145.90	8.27
Colstrip 2	Lime/alkaline fly ash	0.78	360	145.90	8.27
Nevada Power					
Reid Gardner 1	Sodium carbonate	0.50	125	87.10	5.78
Reid Gardner 2	Sodium carbonate	0.50	125	87.10	5.78
Reid Gardner 3	Sodium carbonate	0.50	125	150.90	7.40
Northern States Power					
Sherburne 1	Limestone/alkaline fly ash	0.80	740	102.60	5.43
Sherburne 2	Limestone/alkaline fly ash	0.80	740	102.60	5.43
Pacific Power and Light					
Jim Bridger 4	Sodium carbonate	0.56	550	118.40	6.81
Pennsylvania Power					
Bruce Mansfield 1	Lime	3.00	917	144.20	11.31
Bruce Mansfield 2	Lime	3.00	917	144.20	11.31
Bruce Mansfield 3	Lime	3.00	917	181.10	10.27

(continued)

TABLE 10. ADJUSTED CAPITAL COSTS AND ANNUAL REVENUE REQUIREMENTS FROM THE FGDIS (Continued)

Utility/unit	Process type	Coal sulfur content, %	Equivalent scrubbed capacity, MW	Adjusted capital cost,[a] $/kW	Adjusted annual cost,[a] mills/kWh
Public Service of New Mexico					
San Juan 1	Wellman-Lord	0.80	361	277.90	16.69
San Juan 2	Wellman-Lord	0.80	350	282.20	16.89
Salt River Project					
Coronado 1	Limestone	0.55	320	86.50	7.70
Coronado 2	Limestone	0.55	320	86.50	7.70
South Carolina Public Service					
Winyah 2	Limestone	1.00	140	47.00	1.84
Winyah 3	Limestone	1.00	280	66.60	4.83
Southern Mississippi Electric Power					
R. D. Morrow 1	Limestone	1.64	124	118.50	6.94
R. D. Morrow 2	Limestone	1.64	124	118.50	6.94
Southern Illinois Power					
Marion 4	Limestone	3.75	184	120.80	7.75
Southern Indiana Gas and Electric					
A. B. Brown 1	Dual alkali	3.35	265	88.40	4.98
Springfield City Utilities					
Southwest 1	Limestone	3.50	194	143.40	8.21
Springfield Water, Light & Power					
Dallman 3	Limestone	3.30	205	194.30	14.56
Tennessee Valley Authority					
Widows Creek 8	Limestone	3.70	550	158.10	7.28

(continued)

TABLE 10. ADJUSTED CAPITAL COSTS AND ANNUAL REVENUE REQUIREMENTS FROM THE FGDIS (Continued)

Utility/unit	Process type	Coal sulfur content, %	Equivalent scrubbed capacity, MW	Adjusted capital cost,[a] $/kW	Adjusted annual cost,[a] mills/kWh
Utah Power & Light					
Hunter 1	Lime	0.55	360	75.10	4.66
Hunter 2	Lime	0.55	360	72.60	4.55
Huntington 1	Lime	0.55	366	90.00	5.89

[a] The adjusted capital and annual costs are taken from the Flue Gas Desulfurization Information System (FGDIS). The costs are adjusted to common 1981 dollars.

TABLE 11. CATEGORICAL SUMMARY OF THE ADJUSTED CAPITAL COSTS AND ANNUAL REVENUE REQUIREMENTS FOR OPERATIONAL FGD SYSTEMS

	Capital		Annual	
Category	Range, $/kW	Average, $/kW	Range, mills/kWh	Average, mills/kWh
All	38.3-282.2	118.8	1.6-20.8	7.6
New	38.3-263.9	110.8	1.6-14.6	6.8
Retrofit	60.4-282.2	139.3	4.3-20.8	9.7
Salable	254.6-282.2	271.6	16.7-20.8	18.1
Throwaway	38.3-263.9	110.9	1.6-17.6	7.0
Process				
Limestone	38.3-194.3	98.9	1.6-14.6	6.1
Lime	60.4-210.0	116.5	4.0-17.6	8.1
Dual alkali	87.8-263.9	146.7	5.0-13.9	8.7
Lime/alkaline fly ash	52.5-184.4	122.8	3.0-14.1	7.2
Sodium carbonate	87.1-150.9	110.9	5.8-7.4	6.4
Wellman-Lord	254.6-282.2	271.6	16.7-20.8	18.1
Limestone/ alkaline fly	102.6-102.6	102.6	5.4-5.4	5.4

TABLE 12. SUMMARY - BASE-CASE FGD DESIGN ASSUMPTIONS

Design factor	FGD processes			
	Limestone sludge	Lime sludge	Double-alkali sludge	Seawater[a]
SO_2 removal device	Mobile bed	Mobile bed	Tray tower	Packed bed
Stoichiometry, mol/mol SO_2 removal	1.4	1.05	1.0	-
Design gas velocity, m/sec (SO_2 removal device)	3.8	3.8	2.1	1.8
L/G, liters/m^3				
Presaturator	0.6	0.5	0.5	0.5
Chloride scrubber	-	-	-	-
SO_2 removal device	6.7	7.4	0.9	8.0
Design pressure drop, kPascals (SO_2 removal device)	2.14	2.14	1.25	1.05
Reheat temperature, °C	79	79	79	79
Byproduct/waste management	Clay-lined disposal pond	Clay-lined disposal pond	Clay-lined disposal pond	Returned to sea
Probable accuracy range factors for capital investment estimates	0.85 to 1.20	0.85 to 1.20	0.80 to 1.30	0.70 to 1.50
Case variations[b]	5 fuel variations 200 MW 500 MW 1000 MW	5 fuel variations	5 fuel variations	3 fuel variations low reheat

(continued)

TABLE 12. SUMMARY - BASE-CASE FGD DESIGN ASSUMPTIONS (Continued)

Design factor	FGD processes				
	Lime gypsum	Jet-bubbling limestone	Magnesium oxide	Sodium sulfite	Carbon adsorption
SO_2 removal device	ROTOPART gas scrubber-separator	Jet-bubbling reactor	Spray grid tower	Valve tray	Moving bed
Stoichiometry, mol/mol SO_2 removal	1.01	1.0	1.05	1.0	7.5 kg $/100 kg char
Design gas velocity, m/sec (SO_2 removal device)	12.2	Proprietary	3.8	-	-
L/G, liters/m^3					
Presaturator	-	Proprietary	-	-	-
Chloride scrubber	-	-	0.5	1.6	-
SO_2 removal device	-	Proprietary	3.0	-	-
Design pressure drop, kPascals (SO_2 removal device)	2.44	3.94	3.24	2.64	0.5 first stage 0.3 second stage
Reheat temperature, °C	79	79	79	79	None
Byproduct/waste management (sales credit, $/short ton)	Gypsum 3.00/ton	Gypsum 3.00/ton	Sulfuric acid 25.00/ton 100% acid	Sulfuric acid 25.00/ton 100% acid	Sulfur 40.00/ short ton
Probable accuracy range factors for capital investment estimates	0.70 to 1.50	0.70 to 1.50	0.80 to 1.30	0.80 to 1.30	0.70 to 1.50
Case variations[b]	5 fuel variations	5 fuel variations	5 fuel variations	5 fuel variations sulfur production	5 fuel variations

Basis for all base-case processes:
99.2% fly ash removed in ESP and disposed of separately, 95% of S in coal emitted in flue gas, 90% FGD SO_x removal, 4 absorber trains with reheat to 79°C for all wet processes, 2 absorber trains and no reheat for the carbon adsorption process, 3.5% S (5,830 kcal/kg) coal.

[a]Seawater base-case fuel is 1.4% S coal.

[b]Case variation fuels, 0.8% S (5,280 kcal/kg), 1.4% S (7,000 kcal/kg), and 2.0% S (6,110 kcal/kg) bituminous coal; 0.5% S (4,390 kcal/kg) lignite and 2.5% S (10,490 kcal/kg) oil. 3.5% S and 2.0% S coal not used in seawater process.

TABLE 13. SUMMARIZED RESULTS - ENERGY, LAND, CAPITAL INVESTMENT, AND ANNUAL REVENUE REQUIREMENTS

Process	Energy consumption, % of input energy	Land hectares	Capital Investment		Annual revenue requirements	
			10^6 $	$/kW	10^6 $	mills/kWh
Limestone sludge						
0.8% S in coal	3.3	42	40.0	80	11.2	3.7
1.4% S in coal	3.2	56	41.6	83	11.5	3.9
2.0% S in coal	3.2	78	45.5	91	12.6	4.2
3.5% S in coal	3.3	127	53.1	106	14.6	4.9
0.5% S in lignite	3.3	34	39.0	78	10.9	3.7
2.5% S in oil	2.7	70	40.6	81	11.4	3.8
200 MW, 3.5% S in coal	3.4	64	26.3	132	7.0	5.9
700 MW, 3.5% S in coal	3.3	163	71.0	101	19.7	4.7
1000 MW, 3.5% S in coal	3.3	213	93.9	94	26.4	4.4
Lime sludge						
0.8% S in coal	3.3	35	37.8	76	11.1	3.7
1.4% S in coal	3.1	47	38.9	78	11.5	3.8
2.0% S in coal	3.2	66	42.0	84	12.6	4.2
3.5% S in coal	3.2	107	47.7	96	15.0	5.0
0.5% S in lignite	3.3	28	37.2	74	10.8	3.6
2.5% S in oil	2.5	57	37.3	75	11.4	3.8
Dual (double) alkali sludge						
0.8% S in coal	2.5	38	40.5	81	11.2	3.7
1.4% S in coal	2.4	49	42.2	84	11.8	3.9
2.0% S in coal	2.5	67	46.0	92	13.1	4.4
3.5% S in coal	2.5	104	53.2	107	16.0	5.3
0.5% S in lignite	2.5	36	39.6	79	10.8	3.6
2.5% S in oil	1.9	53	40.7	81	11.9	4.0
Seawater						
0.8% S in coal	4.2	2	29.6	59	8.7	2.9
1.4% S in coal	4.2	2	30.0	60	8.7	2.9
0.5% S in lignite	4.2	2	29.1	58	8.5	2.8
2.5% S in oil	3.5	2	27.9	56	8.6	2.9
1.4% S in coal, low reheat	2.8	2	28.6	57	7.8	2.6
Lime gypsum						
0.8% S in coal	2.9	5	35.5	71	9.8	3.3
1.4% S in coal	2.9	5	36.5	73	10.3	3.4
2.0% S in coal	3.2	5	39.2	78	11.4	3.8
3.5% S in coal	3.7	5	44.0	88	13.7	4.6
0.5% S in lignite	2.9	5	34.9	70	9.6	3.2
2.5% S in oil	2.5	5	34.8	70	10.3	3.5

(continued)

TABLE 13. SUMMARIZED RESULTS - ENERGY, LAND, CAPITAL INVESTMENT, AND ANNUAL REVENUE REQUIREMENTS (Continued)

Process	Energy consumption, % of input energy	Land hectares	Capital investment		Annual revenue requirements	
			10^6 $	$/kW	10^6 $	mills/kWh
Jet-bubbling limestone						
0.8% S in coal	3.4	5	42.0	84	10.9	3.7
1.4% S in coal	3.3	5	42.0	84	10.9	3.6
2.0% S in coal	3.3	5	43.8	88	11.4	3.8
3.5% S in coal	3.4	5	47.0	94	12.2	4.1
0.5% S in lignite	3.3	5	42.1	84	11.0	3.7
2.5% S in oil	2.6	5	38.5	77	10.2	3.4
Magnesium oxide						
0.8% S in coal	3.9	3	48.9	98	12.9	4.3
1.4% S in coal	4.1	3	52.0	104	13.7	4.6
2.0% S in coal	4.8	3	58.1	116	15.1	5.0
3.5% S in coal	6.3	3	68.4	137	17.5	5.9
0.5% S in lignite	3.8	3	47.1	94	12.6	4.2
2.5% S in oil	3.7	3	44.6	89	12.0	4.0
Sodium sulfate						
0.8% S in coal	4.1	3	46.8	94	12.2	4.1
1.4% S in coal	4.6	3	50.3	101	13.1	4.4
2.0% S in coal	4.7	3	56.9	114	14.8	4.9
3.5% S in coal	8.1	3	68.7	137	17.9	6.0
0.5% S in lignite	3.9	3	44.8	90	11.8	3.9
2.5% S in oil	4.5	3	44.2	88	11.8	3.9
3.5% S in coal, sulfur production	9.9	3	71.3	143	21.0	7.0
Carbon adsorption						
0.8% S in coal	0.6	5	51.2	102	13.9	4.6
1.4% S in coal	0.8	5	54.2	108	15.8	5.3
2.0% S in coal	1.0	5	60.8	122	20.0	6.7
3.5% S in coal	1.7	5	73.5	147	28.5	9.5
0.5% S in lignite	0.5	5	49.5	99	12.8	4.3
2.5% S in oil	0.9	5	53.7	107	17.5	5.9

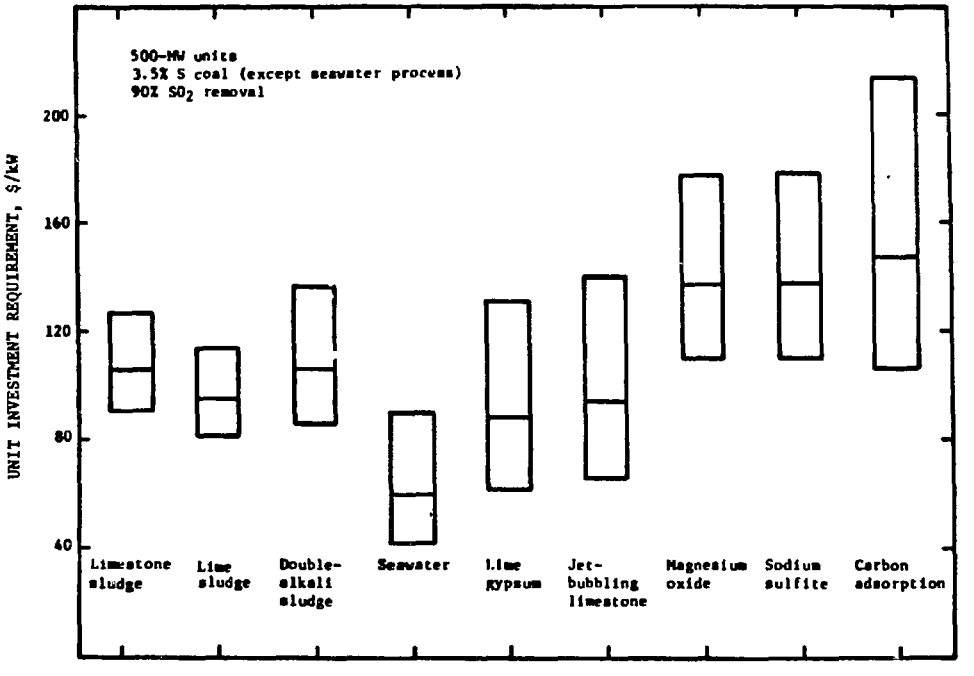


Figure 6. Base-case unit investment range for alternate processes.

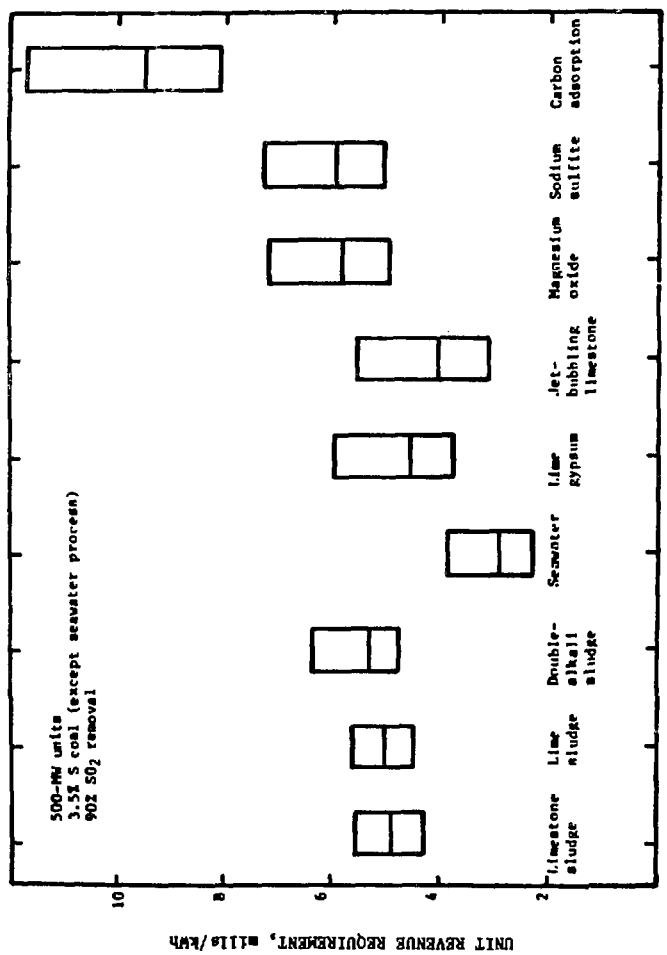


Figure 7. Base-case unit revenue requirement range for alternate processes.

Comparison of Two Cost Methods

Despite the many differences between the actual systems and the design premises used in the TVA studies, we have attempted to compare the results of the two approaches.

The capital costs for limestone and lime slurry processes are plotted against coal sulfur content with high and low accuracy ranges for the 500 MW, 90 percent SO_2 removal base case in the NATO CCMS Study, in Figures 8 and 9, respectively. Superimposed on these plots are the actual adjusted costs expressed in 1979 dollars, for each of the lime and limestone systems for which data exists in the FGDIS, regardless of unit capacity, Also plotted is the average value (intersection point) from the FGDIS for all of the limestone and lime slurry processes expressed in 1979 dollars.

The same process procedure was used in Figures 10 and 11, for the annual revenue requirement comparisons for limestone and lime slurry processes, respectively. Here the average values for the adjusted real costs did not fall within the shaded area, but were somewhat high. Investigation of some of the specific high values (e.g., Duquesne Light Co., Phillips and Elrama; Springfield Water, Light and Power, Dallman; and Indianapolis Power & Light, Petersburg) for annual revenue requirements yielded several recurrent reasons for abnormally high costs. Some of these are:

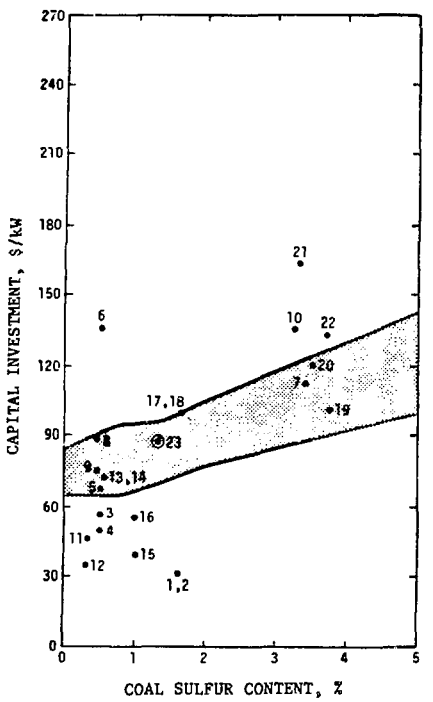
- Waste disposal at a distant off-site landfill; in one case a disposal fee is charged.
- Extensive modifications were made to the systems, after the system was in operation. These modifications were charged to annual costs, or at least, added to capital, thus raising annual revenue requirements due to amortization of costs.
- Unusually expensive materials of construction due to special application such as high-chloride coal.

Since these factors were not part of the TVA premises, it is understandable that the resulting actual costs are higher than the TVA design model costs.

To put FGD costs in perspective, it is useful to compare them to costs for coal-fired power plants. We estimate that the capital cost and annual revenue requirement for such an uncontrolled plan are $710/kW and 39 mills/kWh in 1979 dollars, respectively. Thus, based on the TVA design models, the costs of a lime-

stone FGD system is about 13 percent of the total cost of the FGD controlled power plant; and the FGD annual revenue requirement is about 11 percent of the controlled plant revenue requirement.

Recently, TVA justified revision of their previous design and economic premises based on changing economic conditions, fuel use patterns, developments in economic evaluation techniques, developments in FGD technology, and environmental legislation. The new premises are generally more conservative, and result in capital costs and annual revenue requirements, which are almost double what they were under the old premises. A discussion of the "new" vs "old" premises is given in, FGD Economics in 1980.[2]



LEGEND

Alabama Electric
(1) Tombigbee 2
(2) Tombigbee 3

Arizona Electric Power
(3) Apache 2
(4) Apache 3

Arizona Public Service
(5) Cholla 1
(6) Cholla 2

Central Illinois Light
(7) Duck Creek 1

Colorado Ute Electric
(8) Craig 1
(9) Craig 2

Indianapolis Power & Light
(10) Petersburg 3

Kansas Power & Light
(11) Jeffrey 1
(12) Jeffrey 2

Salt River Project
(13) Coronado 1
(14) Coronado 2

South Carolina Public Service Authority
(15) Winyah 2
(16) Winyah 3

South Mississippi Electric
(17) R D Morrow 1
(18) R D Morrow 2

Southern Illinois Power Co-op
(19) Marion 4

Springfield City Utilities
(20) Southwest 1

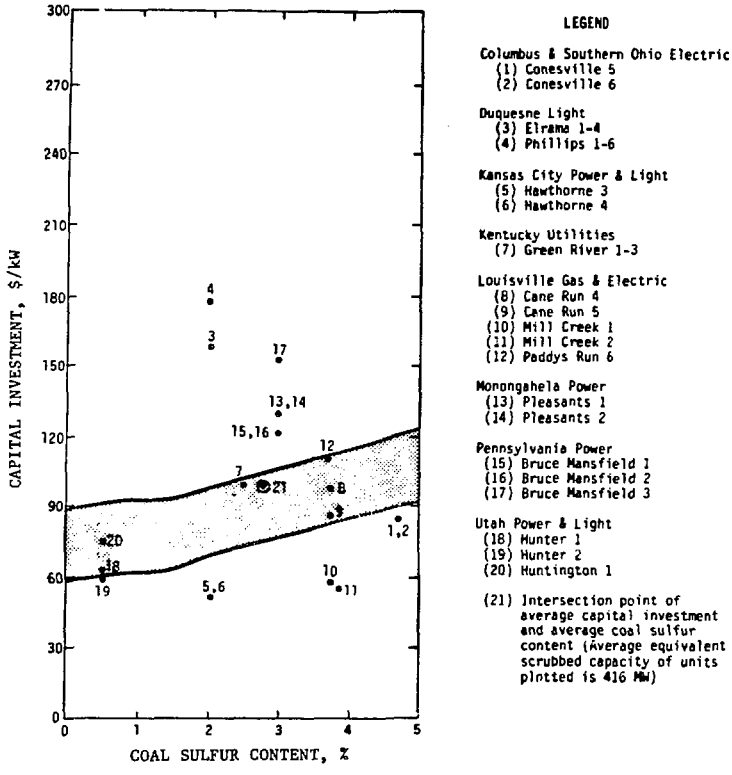
Springfield Water, Light & Power
(21) Dallman 3

Tennessee Valley Authority
(22) Widows Creek 8

(23) Intersection point of average capital investment and average coal sulfur content (Average equivalent scrubbed capacity of units plotted is 281 MW)

NOTE: Shaded region above is based on TVA cost projections for new 500 MW units in common 1979 dollars, as reported in "NATO/CCMS Flue Gas Desulfurization Pilot Study, Phase II, August 1980."

Figure 8. Limestone FGD capital cost comparison, adjusted actual vs modeled.



LEGEND

Columbus & Southern Ohio Electric
(1) Conesville 5
(2) Conesville 6

Duquesne Light
(3) Elrama 1-4
(4) Phillips 1-6

Kansas City Power & Light
(5) Hawthorne 3
(6) Hawthorne 4

Kentucky Utilities
(7) Green River 1-3

Louisville Gas & Electric
(8) Cane Run 4
(9) Cane Run 5
(10) Mill Creek 1
(11) Mill Creek 2
(12) Paddys Run 6

Monongahela Power
(13) Pleasants 1
(14) Pleasants 2

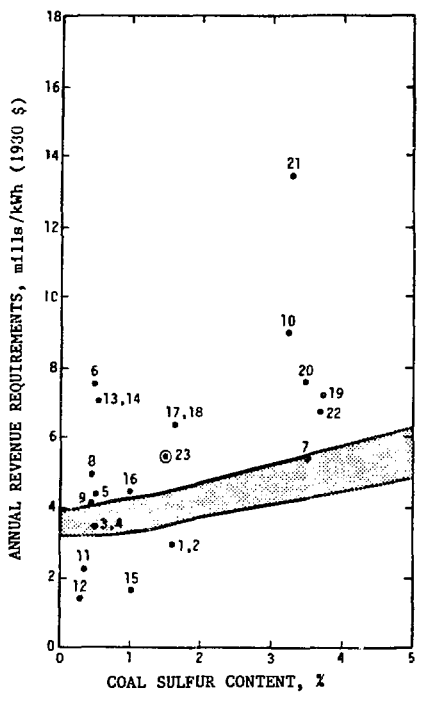
Pennsylvania Power
(15) Bruce Mansfield 1
(16) Bruce Mansfield 2
(17) Bruce Mansfield 3

Utah Power & Light
(18) Hunter 1
(19) Hunter 2
(20) Huntington 1

(21) Intersection point of average capital investment and average coal sulfur content (Average equivalent scrubbed capacity of units plotted is 416 MW)

NOTE: Shaded region above is based on TVA cost projections for new 500 MW units in common 1979 dollars, as reported in "NATO/CCMS Flue Gas Desulfurization Pilot Study, Phase II, August 1980."

Figure 9. Lime FGD capital cost comparison, adjusted actual vs modeled.



LEGEND

Alabama Electric
(1) Tombigbee 2
(2) Tombigbee 3

Arizona Electric Power
(3) Apache 2
(4) Apache 3

Arizona Public Service
(5) Cholla 1
(6) Cholla 2

Central Illinois Light
(7) Duck Creek 1

Colorado Ute Electric
(8) Craig 1
(9) Craig 2

Indianapolis Power & Light
(10) Petersburg 3

Kansas Power & Light
(11) Jeffrey 1
(12) Jeffrey 2

Salt River Project
(13) Coronado 1
(14) Coronado 2

South Carolina Public Service Authority
(15) Winyah 2
(16) Winyah 3

South Mississippi Electric
(17) R D Morrow 1
(18) R D Morrow 2

Southern Illinois Power Co-op
(19) Marion 4

Springfield City Utilities
(20) Southwest 1

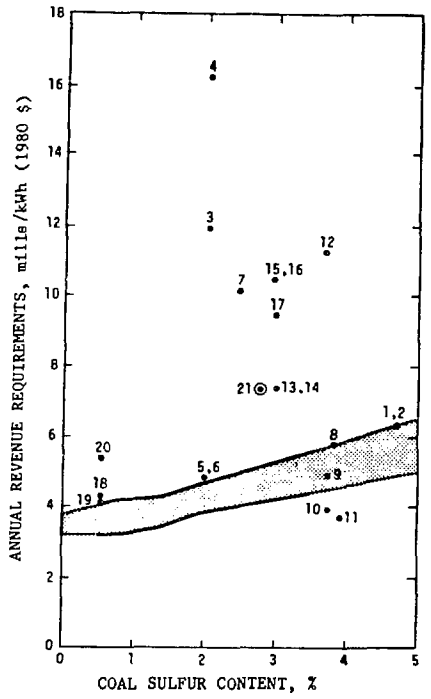
Springfield Water, Light & Power
(21) Dallman 3

Tennessee Valley Authority
(22) Widows Creek 8

(23) Intersection point of average annual revenue requirements and average coal sulfur content (Average equivalent scrubbed capacity of units plotted is 281 MW)

NOTE: Shaded region above is based on TVA cost projections for new 500 MW units in common 1980 dollars, as reported in "NATO/CCMS Flue Gas Desulfurization Pilot Study, Phase II, August 1980."

Figure 10. Limestone FGD annual revenue requirements comparison, adjusted actual vs modeled.



LEGEND

Columbus & Southern Ohio Electric
(1) Conesville 5
(2) Conesville 6

Duquesne Light
(3) Elrama 1-4
(4) Phillips 1-6

Kansas City Power & Light
(5) Hawthorne 3
(6) Hawthorne 4

Kentucky Utilities
(7) Green River 1-3

Louisville Gas & Electric
(8) Cane Run 4
(9) Cane Run 5
(10) Mill Creek 1
(11) Mill Creek 2
(12) Paddys Run 6

Monongahela Power
(13) Pleasants 1
(14) Pleasants 2

Pennsylvania Power
(15) Bruce Mansfield 1
(16) Bruce Mansfield 2
(17) Bruce Mansfield 3

Utah Power & Light
(18) Hunter 1
(19) Hunter 2
(20) Huntington 1

(21) Intersection point of average annual revenue requirements and average coal sulfur content (Average equivalent scrubbed capacity of units plotted is 416 MW)

NOTE: Shaded region above is based on TVA cost projections for new 500 MW units in common 1980 dollars, as reported in "NATO/CCMS Flue Gas Desulfurization Pilot Study, Phase II, August 1980."

Figure 11. Lime FGD annual revenue requirements comparison, adjusted actual vs modeled.

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VI

FUTURE PROSPECTS FOR ILLINOIS ELECTRIC UTILITIES

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27. Utilities, Regulators, and Consumers

Jeffrey Paulson
Assistant Illinois Attorney General

The future for electric utilities in Illinois depends primarily on the behavior of three major actors -- the utilities, regulatory agencies, and consumers. To be sure, external factors and circumstances will obviously influence the future. National and state politics is one such influence, and the economy is another, both of which can be extremely volatile. The political future cannot be predicted nor can the behavior of the economy be predicted, although the connection between economic growth and utility growth is much more tenuous than it has been historically. What is predictable is the reaction of the three actors -- Illinois utilities, regulators and consumers -- to external stimuli. The interplay among these three groups will be the prime determinants of the future of electric power in this State.

A brief description of the current status of these institutions follows. Electric utilities are investor-owned. The management of these utilities has one dominant goal: the maximization of shareholder wealth. The provision of electric service is the means by which the investors' return is earned. First and foremost, utility actions are governed by investor interests and by management interests when the two do not coincide. Utility motivations cannot be expected to change in the future as long as they remain investor-owned.

Second, and perhaps more important, are the regulators, in particular, the Illinois Commerce Commission. The function of state utility regulation, in part, is to replace the effects of competition by utilizing existing, predictable utility motivations and to provide sufficient incentives to utilities to promote efficiency and a proper balance of consumer and investor interests. The present Illinois Commerce Commission and its predecessors have failed to perform that function -- to the detriment of consumers and to the benefit of utilities and their owners and managers. Electric utilities in the State are optimistic about their future and that optimism is based on past and prospective regulatory treatment. The Illinois Commerce Commission has consistently refused to punish utilities when it counts, choosing instead to serve as a security blanket to cushion utilities from their mistakes. Consequently, instead of efficient electric utilities, almost every Illinois

electric utility has significant excess capacity which is paid for by consumers. Ongoing construction programs which may be of little or no ultimate benefit are causing a cycle of massive and frequent rate increases. Given the current system of utility regulation, there is no reason to expect a change for the better from these existing deficiencies.

The third element of this equation, and the most important, is the utility consumer. Currently, consumers are a passive force, whether or not they are aware of their lack of power. In fact, they tend not to be aware of their lack of input, because the system carefully nurtures the impression that consumers are heard Various consumer advocates, including the Attorney General's office, intervene on behalf of the consumer at Commission hearings. The interventions routinely fail, for one of two reasons. Either intervenors lack the resources and expertise to create a sufficient record, or the Commission and its staff, sometimes with utility help, concentrate their efforts to construct a record which will allow the Commission to ignore or reject intervenor arguments.

Public hearings, rather than encouraging effective input, compound the problem of consumer inaction in the long run. Public statements are not sworn and do not play a significant role in the Commission's decisions. The public, however, is led to believe otherwise, and therefore does not attempt more effective actions. In this fashion, utilities and the Commission allow angry consumers to vent their frustrations harmlessly, and the potential for consumer interference with the current system is eliminated.

Finally, there is an absence of accountability to the public on the part of commissioners, staff, and hearing examiners. The chain of accountability runs only to the person who appoints the Commission - the Governor. In sum, the public and its representatives are precluded from participating in or influencing the Commission's decisions.

The current balance of power will continue until the system is changed. Consumers are recognizing that they are being asked to bear higher costs than are necessary for utility service, and they are realizing that they have nothing to say about it. And, if you assume that consumers are intelligent and persevering and will channel their anger effectively, then it can be predicted that there will be greater consumer input into utility regulation in the future, probably in the form of an elected commission as proposed by Senator Demuzio and by Attorney General Fahner. In that event, electric utilities will be forced to reassess their activities with greater concern for public as well as private interests.

28. The Future Illinois Utility Market

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Chairman
Illinois Commerce Commission

In examining the future prospects for Illinois electric utilities, it seems clear that we are not discussing their viability - either financial or corporate. This point is stressed because so much has been made in some circles of the temporary financial distress these companies have experiences in the last several years. Investors, at least, are bullish on the industry. Two months ago, for example, only two electric utilities were able to sell their equities at book value or greater. As of last month, there were thirteen -- a list that included Illinois Power and Central Illinois Public Service Company. There were another dozen runners-up with stocks selling between 95% and 100% of book value.

This does not, of course, mean that these utilities have suddenly and mysteriously solved their cash flow problems or that their earnings have shown substantial real increases. They have not. Investors have bid up electric utility stock prices because interest rates are expected to moderate and because, over the long haul, these companies are expected to provide investors with a reasonable, bond-like return. If viability were an issue with these companies, investors would be the first to worry and stock prices would fall rather than increase to reflect that risk.

In order to lay a proper foundation for this discussion of future prospects for the industry, it is instructive to briefly review the events and the circumstances that have led to the current situation.

With the advantage of hindsight, it seems obvious today that utility system planners were caught with their pencils down when the oil embargo occurred in 1973. At that time, a number of new plants were either under construction or well along in the planning stages in Illinois. The utility industry, of course, was in impeccable company in 1973, since most of the world's industrial and governmental leadership were also caught off guard. It is worth observing, incidentally, that no new certificates for generating units have been granted by the Illinois commerce Commission since early 1974.

The events that have shaken the industry in the last nine years can be placed in better perspective by considering the basic mode of operation of an electric utility. All electric utilities, except perhaps those

blessed with federally funded hydro projects, use vast quantities of three things -- fuel, powerplants and borrowed money. Beginning with the embargo in 1973, the cost of these essential ingredients literally went wild.

The prices of all utility boiler fuels -- oil, natural gas, coal and even uranium -- increased at a rate far in excess of the rate at which the general price index increased in that period. To a large extent, it was principally these fuel increases that cause electricity prices to move upward, although not as rapidly or as far as the prices of many other commodities during the late 1970's.

The cost of constructing new powerplants doubled in just a few years as a result of several factors. First, many construction projects were delayed, either because of shortfalls in anticipated load or because of regulatory changes made by the Environmental Protection Agency or the Nuclear Regulatory Commission. Some of these changes added directly to the cost of construction and others affected costs indirectly through the actual delays. Some of the plants experienced delays as a consequence of engineering and construction difficulties and the availability of critical components. Labor shortages actually plagued some nuclear construction projects.

The delays became extremely costly as interest rates moved to their highest levels in the century, creating serious cashflow problems for the companies. It is also significant that the overwhelming majority of the powerplants under construction were coal or nuclear fueled and were scheduled to displace older and more costly oil fired units. So these delays meant putting off fuel savings for consumers at just the moment when consumers were hardest hit with oil prices increases.

Finally, the cost of "borrowed money" to the electric utility industry had never been higher than in the period. It is surprising how much misunderstanding can develop on the issue of utility borrowing, and perhaps that can be clarified. When an electric utility constructs a power-plant, the architects and the contractors insist on being paid in full when the unit is completed. They actually send the utility a bill and they usually show no interest whatsoever in an extended financing plan for payment. Under Illinois statutes, the Commerce Commission will not allow the utility to collect that entire amount from customers in a single year. To do so would mean a multibillion dollar rate increase each time a new powerplant was completed. Rather, the Commission requires the utility to recover those construction

costs from customers over the thirty year life of the plant, as the plant provides useful service.

To reconcile this extended program of cost recovery with the requirement that the contractor be paid at the completion of work means simply that the utility has to go to the capital markets and borrow money. When it does this, it carries no special privileges just because it is regulated utility. Utilities compete with the federal government, with consumers and with other corporations, both domestic and international, for these funds and they pay the going rate. Reasonable and prudent utility borrowing is a legitimate and necessary cost of doing business and it is ultimately reflected in electricity prices.

In reality, of course, powerplant financing is somewhat more complex. The contractor typically requires progress payments as the construction work proceeds. This neccesitates a certain amount of borrowing by the utility to fund those progress payments, and this borrowing represents a cost that the utility generally cannot recover until the powerplant is complete and is generating electricity for consumers. During normal and stable periods, electric utilities were able to bear this delay in cost recovery with no serious consequences. Because of long construction delays, however, the utility had to wait longer than expected to recover costs, and increases in construction costs further aggravated the problem. But the final straw was the record high cost of borrowing to bridge this gap. The cashflow burden that this confluence of catastrophies placed on the electric utility industry was real and it was intense. In fact, some companies found that they could not continue to finance construction at all under their original schedules because of these problems.

The practice of permitting electric utilities to recover some of the construction costs as they occur, known as Construction Work In Progress or CWIP, was implemented very judiciously in order to avert consequences that could have been highly injurious to consumers.

As if these problems were not enough, the utility could ponder the effect on its load and its sales of persistently sluggish national economic growth, a chaotic flurry of complex energy legislation, costly fuel use prohibitions, at times misguided experimental ratemaking projects and a growingly and understandably hostile consuming public.

The electric utility industry has emerged from this period somewhat leaner, but without any permanent damage. Investor confidence in the future of the industry seems acceptable, and the question really is

whether the worst is over. It is from this foundation, then, that any discussion of the industry's future prospects must follow.

The first focus is on the nature and the makeup of the future market that the electric utility industry in Illinois will serve. The choices and constraints the industry will face in responding to that market will be examined later.

The usual point of reference, when examining the future demand for electricity, is the so called "golden era" of the fifties and sixties. That period was characterized by stable, predictable and rather high growth rates. The commercial and industrial load kept pace with moderate but consistent GNP growth, and residential air conditioning had not yet approached saturation levels. New housing units were being added at record rates and in many parts of the country and in this state they utilized electric space heating systems. The cost of money and the underlying inflation rate were modest, and new powerplants were increasing in size to exploit scale economies in the generation of electricity. It is generally recognized that the real price of electricity to consumers during that period either held constant or actually declined. It was a "golden era" for the industry, the investor and the consumer. Regulators were also more popular then when they called utilities in to lower rates.

The interesting question now is whether it is the "golden era" or the last decade that is a more appropriate guide to the future of the industry. Certainly, there are not many who believe we can return to the stable pattern of the sixties. But many analysts do see a continuation of the anomolous seventies as model scenario for the next few decades. They, argue, not very persuasively, that air conditioning saturation, minimal real economic growth, conservation and a good measure of wishful thinking will all add up to reduce future electric utility load growth to minimal levels. An alternative view that is arguable better grounded in the realities of this state's economic fortunes is offered.

It is plainly dangerous to read the future from the remains of the last decade. If the next decades witness the same trebling of real fuel prices, a return to 18% interest rates and comparable increases in powerplant construction costs, then the future prospects for the electric utility industry will be the very least of our concerns. It is imperative that planners assume at least a modest rate of real economic growth through the year 2000 or they risk creating a self-fulfilling prophesy. With that real growth, vitalized by more tractable interest rates,

the housing industry should resume a healthy growth rate. Industrial demand for electricity is extremely sensitive to the level of economic activity and there is an abundance of hard data to confirm this. One can pick out individual utility companies throughout the country that have been hard hit by plant closings and other products of the current recession and measure the decline in load, which is directly attributable to those factors.

The current problems created by natural gas pricing policies at the federal level have brought burner-tip gas prices to levels where electric space heating is increasingly attractive as an economic alternative. This point if often missed by those who delight in calling attention to the declining ration of BTU's per dollar of GNP as the harbinger of a shrinking electric utility industry. Although it is true that less energy is being used in the economy, electricity is commanding an increasing share of that energy. Interfuel competition has been fierce since 1973 and will continue well into the future to the ultimate benefit of consumers if markets are freed to accomplish this.

The primary fuels used to generate electricity in Illinois are coal and uranium. To the extent that the prices of these fuels escalate at the same rate as the general price level, then it is inescapable that the market for electricity will expand into areas previously served by gas and oil. Gas and oil prices are generally projected to increase at a rate higher than coal and uranium prices.

A few years back, the Illinois Department of Energy and Natural Resources commissioned the Energy Resources Center at the University of Illinois, Chicago, to undertake a study of the feasibility of electric vehicles in the Chicago area. The study found that significant penetration of electric vehicles was possible and that between 500,000 and 1 million electric vehicles could be competitively operating in the Chicago area by the year 2000. With efficiencies of 0.37kwh/mile and usage of 7500 miles per year, these vehicles could present a load of between 1.4 and 2.8 billion kwh/year to the Commonwealth Edison system. The real attractiveness of electric vehicles, of course, is that their battery charging cycle would be concentrated in the off-peak hours and would have the effect of driving up coal and nuclear base load unit capacity factors.

Overall, there is a consensus among industry analysts that the long term compound peak load growth will be in the vicinity of 2% per year. Others have charged that this is a low to modest estimate and that

3% would be far more consistent with expected long term real GNP growth through 2000. Either way, growth prospects are good.

A return to the 7% growth pattern of the sixties is not forseen, but this does not rule out the possibility that relative to the prices of other goods and services, electricity prices may once again decline. The market for electricity in the next decade is uncertain. But the prospects are positive for continued growth, for greater stability and for a moderation of cost pressures.

Now let us look at how electric utilities will respond to the market challenges outlined. First is an increased emphasis on flexibiilty in planning and construction to serve a load that is more uncertain in the short run. This may translate into a downsizing of powerplants to reduce construction times and also to minimize any losses that could arise from overshooting target reserve margins.

The Illinois Commerce Commission had not granted any new certificates for powerplant construction since early 1974. In addition, the ICC does not expect to see any new requests for certificates for several more years. The first new request will probably come from Central Illinois Light Company for Duck Creek 2, a 400 megawatt coal unit that could go into operation as early as 1990. Commonwealth Edison is tentatively scheduling four 550MW coal units for operation in 1996, a full fourteen years from now. Central Illinois Public Service Company has a 400 MW coal unit on the board for operation in 1997 and a 100 MW peaker planned for 1996.

By any standard, this is a light construction program for the Illinois electric utility industry spanning an eighteen year period. It is partly because of this fact that the leveling off of future electricity prices is a distinct possibility in this state. It should be added that these utility capacity plans are premised on a statewide average peak load growth in the range of 2 percent through the year 2000.

There are several reasons why this load growth can be met with so spartan a building program in Illinois. Certainly a major factor is that some utilities have just completed or are winding up a major construction cycle. Most of the plants nearing completion were constructed at costs that are flatly unattainable ever again. The entire economic infrastructure of Illinois should derive significant long term benefits from the availability of this inexpensive capacity.

But other considerations are involved as well.

One area often overlooked is the increased attention given to intercompany coordination in the planning of new generating units and the tripling of interchange sales over the past two decades. On a national basis, interchange sales as a percentage of total annual generation have grown from approximately 7% in 1961 to 21% in 1979. The effect of this trend for consumers has been a sharing in the benefits of the efficient dispatch of electricity from sources outside of a utility's own system. It is expected that there will be an increased utility interest in load management initiatives in the future. Load management has probably been somewhat oversold as an attractive alternative. It does not always make good econimic sense and it is very case specific for each utility, depending on the load and system supply options faced in particular years. Where and when it does make sense, however, it is expected to be adopted; and it is my position that the Illinois Commerce Commission has an obligation to enforce that policy.

Finally, the proper pricing of electricity so that consumers are able to see the full cost of their consumption decisions is important. Only if this happens will there be any rational connection between consumption on the one hand and utility planning decisions on the other. We will experience excessive peak loads and excessive capacity to meet those loads if we price peak load electricity below its actual cost. And just as surely, we will see the costly underutilization of off-peak capacity if off-peak prices are above costs. Illinois has made considerable progress in implementing efficient electricity prices and that this action will help hold down costs over the coming decades.

The future prospects for the electric utility industry in Illinois are good for a reliable and a competitive supply of electricity to serve the state's needs. A gradual but inexorable moderation in those costs of providing electricity that have recently caused real and justifiable concern among consumers is anticipated. The lessons of the past decade must not be lost on utility managers or regulators in the future. The net result will be a positive benefit to the customer of utilities that is clearly in the public interest.

29. A Look at the 70's to Project the 80's

Charles W. Wells
Executive Vice President
Illinois Power Company

It might be useful to look back at the past decade to see what has happened to the electric utility industry and what trends, if any, seem to be developing.

Most of us have forgotten that at about the beginning of the decade of the 70's portions of the United States experienced some rather severe power outages. The electric industry was criticized for lack of foresight and planning to meet the energy needs of the 70's. The following is a short excerpt from Illinois Power President Wendell J. Kelley's message to our stockholders in the 1970 Annual Report: "We see good reasons for a more optimistic view of the future of our industry than that taken by some publicity-conscious officials and professional critics. Certainly we see little factual basis for their sometimes hysterical alarms about nation-wide brownouts, blackouts and the destruction of a habitable environment."

It is an interesting paradox that today, just 10 years later, the utility industry is being severely criticized for what our critics believe is the building of too much electric capacity for the 80's which they say is responsible for the increased cost of electricity.

First of all, our optimism in 1970 proved true and the country did not experience widespread electrical blackouts. We furnished the energy on time for growth in Illinois.

Secondly, my own personal view of the 80's is still an optimistic one for our industry in spite of what our critics are saying--and what they are saying falls far short of facing up to all the reasons for the increasing cost of energy.

As an example, during the decade of the 70's the average of a kwh to our residential customers increased 96 percent. During this same time period the cost of Illinois coal to generate that kwh of electricity rose 526 percent. Our interest costs rose 307 percent, our taxes rose 124 percent, our cost of workman's compensation rose 435 percent, and our cost of meeting environmental requirements rose 3725 percent.

To keep our 96 percent increase in the cost of a kilowatt-hour in perspective, it is interesting to

note that the cost of state government rose 203 percent during that 10-year period and the cost of running the General Assembly rose 177 percent.

During this same time frame, the annual dividend to our common stockholders increased from $2.10 to $2.35 a share or 11.9%, while the average market price of one share of common stock dropped from around $40.00 to about $20.00, or a 50% loss in value.

In the face of this not-too-promising historical trend, I am still cautiously optimistic about the future of the utility business in Illinois. However, there are just too many variables to be able to be absolutely certain. The Illinois Commerce Commission is one of those major variables. In this case the question, of course, is whether the ICC will allow prices to cover all our costs plus an adequate return. In addition, the public is angry about the state of the whole economy and finds that one place they can fight back is at regulated utilities. The Illinois legislature is reflecting public unrest by introducing an increasing number of changes in the law. On the national front, federal law, regulations, and changing interpretations of those regulations are major factors in determining what fuel we use and the costs of building new power plants.

Against this background of uncertainty, the utility must survive the present and plan for the future. Future demand for electricity is more difficult to forecast today than it has ever been. But, at the same time, it is one of the basic inputs to a sustained economic health. In order to forecast electrical demand you must first make long-term assumptions on unknowns such as the world economy, the U.S. economy, and world trade. It is necessary to guess on the competitive success of U.S. basic industry and Illinois' competitive success in retaining and expanding its share of industrial and business activity. We must estimate the success we will have in research and development to improve efficiency in energy use and, last but not least, we must determine what housing standards and living standards will be acceptable to the people.

A few years ago our growth was relatively stable at around 7% per year and has been decreasing each year to the present forecast of 2-3%. We are all smarter today than we were five years ago, and that includes electric utilities. We now know that there is price elasticity in the demand for electricity. We know that the customer will conserve on energy use. We further know that we cannot depend upon trends of the past to determine future electric use but must depend more upon econometric forecasting models. We

have experienced the closing of major industrial plants. On the other hand, we do not know if there will be new large industries locating in the state or if an expanding economy will cause our existing customers to grow rapidly.

The forecast for electrical growth determines whether electric utilities will need to invest more capital in additional plants. If we decide that no additional plants are needed, then we concentrate upon improving present operations. If there is opportunity to improve these operations, then the prospects for Illinois utilities will improve. If, on the other hand, additional plants are required, then we add the complication of acquiring the needed capital to build them. One of the initial and important questions on the prospects for the future becomes: How much additional capital will the utilities need and under what conditions can they get that capital on reasonable terms?

You can easily understand why some utilities have decided the best way to improve future prospects is not to build any additional generating capacity. Finish what is under construction and then wait to see what the future brings. This wait-to-see program contains more public risk for utilities than other industries. It takes 10-15 years to plan and build new generation. If we are on the low side, it will take a long time to correct the situation.

Good management practice dictates that we prepare ourselves to be flexible. We must use the best information we have available, but we must be prepared to respond to changing conditions. If load growth is higher than forecasted, then we must have a plan to meet the new conditions in order to improve the economy as a whole. It is in the public interest that utilities prepare to handle the most difficult scenario that prudent forecasting demands. In order to accomplish this, electric utilities must strive to be financially healthy and alert to customer needs. All that we can be sure of is that our forecasts are wrong. If we are to respond to change, we must first recognize the change and then be able to build if we have to.

Most of us seem to be focusing on the present and not paying enough attention to the future. Building power plants raises rates. Therefore, the public and our regulators encourage utilities not to build. The investor does not want us to build either. He shows preference to those utilities that are winding down their construction program and have not committed to any new construction. With all parties in agreement, it is very easy for a utility to decide not to build

in the near future. But the next step is what must be done to ensure a high probability that we focus on future planning and that all parties involved will strive to make good decisions at the appropriate time. I am convinced that good people usually make good decisions, but it is also axiomatic that these people must concentrate on the right issues. For the past few years it has been difficult to focus on the future when we have been forced to survive in the present. Many of the utilities' best people have been immersed in adversary proceedings trying to improve serious cash flow problems and balance the law on such things as environmental matters. Adversary proceedings are useful to cause opinion to be supported by fact and to cause all parties to consider each other's opinion. But these adversary relationships have existed long enough for prudent practical people to begin to agree upon what is important and to begin to balance their positions. We cannot disregard the present, but if we want the future to be better we must begin to focus on the future. We all have views that are important to the solution, but these views are many times too divergent to allow a consistent decision-making process. We must be more tolerant of each other's position and strive to strike a balance in order that decisions are made in the best interest of the public as a whole. It may be necessary to take a small mortgage on the future in order to survive the present. But we must not bankrupt our future.

In summary, I see no reason why the prospects for electric utilities in Illinois should not be good if the public and regulatory bodies allow the utility to remain or become financially healthy; if the utility operates as efficiently as possible and stays alert to its customers' present and future needs; if the world, national, and state economy provides us the opportunity to prosper; and if all parties begin to agree and work toward common goals that are in the public interest.